Review of Dominion Energy South Carolina, Incorporated's 2021 Integrated Resource Plan Docket Nos. 2019-226-E & 2021-9-E

South Carolina
Office of Regulatory Staff

December 15, 2021

Review of Dominion Energy South Carolina, Inc. 2021 Integrated Resource Plan

Pursuant to Section 58-37-40, South Carolina Code of Laws

December 15, 2021

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Executive Summary

The South Carolina Office of Regulatory Staff ("ORS") provides this report summarizing the review of Dominion Energy South Carolina, Incorporated's ("DESC" or "Company") 2021 Integrated Resource Plan ("IRP") Update ("2021 IRP Update") filed August 17, 2021, in Docket Nos. 2019-226-E and 2021-9-E. ORS, with the assistance of J. Kennedy and Associates, Inc. ("JKA"), has evaluated DESC's 2021 IRP Update to determine if it meets the statutory requirements of S.C. Code Ann. § 58-37-40 ("Section 40"), as amended by the South Carolina Energy Freedom Act ("Act 62"), and the requirements of the Public Service Commission of South Carolina's ("Commission") Order No. 98-502.

Act 62 was signed into law by Governor McMaster on May 16, 2019. Act 62 amended and expanded the prior Section 40 IRP requirements. Act 62 includes a list of specific information that each utility must provide in an IRP, requires that the Commission determine whether the utility's IRP represents the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed,"[1] and sets forth seven factors for the Commission to consider in its determination of whether to approve, require modifications, or reject the utility's resource plan, among other procedural and substantive requirements.

Act 62 also states that any resource plan accepted by the Commission "shall not be determinative of the reasonableness or prudence of the acquisition or construction of any resource or the making of any expenditure."[2] Act 62 further states that the utility retains the burden to prove in a future cost recovery proceeding that any investment and expenditure it makes is reasonable and prudent.[3]

Additionally, Act 62 requires the electrical utility to submit an annual update to the IRP that updates base planning assumptions from the most recently accepted IRP.[4] These requirements include the energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency ("EE") and demand-side management ("DSM") (together, "EE/DSM") forecasts, changes to projected retirement dates of existing units, along with other inputs the Commission deems to be for the public interest.[5] The annual update must describe the impact of the updated planning assumptions on the

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[1] S.C. Code Ann. § 58-37-40(C)(2).

[2] S.C. Code Ann. § 58-37-40(C)(4).

[3] *Id.*

[4] S.C. Code Ann. § 58-37-40(D)(1).

[5] *Id.*

selected resource plan from the most recently accepted IRP—in this case, DESC's Modified 2020 IRP (also referred to as the "Modified IRP").[6]

DESC's 2021 IRP Update addresses the Act 62 requirements for updates to a previously approved IRP. The Company states that the most important objectives as an electric utility are to "provide safe and reliable energy that is clean and affordable."[7] DESC states it "is well positioned to achieve these objectives while creating a sustainable, low carbon energy future."[8]

With the exception of three items that ORS recommends DESC address in reply comments in this IRP, ORS finds the 2021 IRP Update to be reasonable. The recommendations for this IRP are discussed in more detail below, but in brief, 1) ORS recommends the Company provide the same generator level performance data that was provided in the Modified IRP, 2) ORS recommends that DESC discuss the impact of Internal Combustion Turbine ("ICT" or "CT") resources that appear to operate at higher capacity factor levels than would normally be expected, and 3) ORS recommends DESC explain the potential disconnect between Order No. 2021-429 requiring realistic and levelized DSM costs in this IRP.

In addition, as the Commission noted in Order No. 2021-429 accepting DESC's Modified IRP, utilities have the "opportunity and expectation for future improvements in later-arriving IRP Updates and IRP's,"[9] and to that end, ORS provides the following recommendations for further improvement in future IRPs:

- ORS recommends the Company continue efforts to work with Stakeholders as part of the DESC IRP Stakeholder Working Group ("Stakeholder Working Group") to develop a reasonable methodology for predicting a "wide but plausible" range of future loads for the 2022 IRP Update, and begin to use that range of load forecasts in sensitivity analyses.

- ORS recommends that the Company update the Reserve Margin Study for the next comprehensive IRP in 2023.

- ORS recommends the Company continue to provide PLEXOS to intervenors in all future IRPs and IRP Updates.

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[6] *Id.*

[7] DESC 2021 IRP Update, Docket 2021-19-E, August 17, 2021, p. 4

[8] *Id.*

[9] Docket No. 2019-226-E, Order No. 2021-429, June 18, 2021, p. 17.

- ORS recommends that the Company ensure that levelized cost of saved energy ("LCSE") assumptions are discussed collaboratively with Stakeholders as part of the Energy Efficiency Advisory Group ("EEAG"), and during that process, assumptions used should be thoroughly explained and justified. All Stakeholders should be permitted the opportunity to express their views in a fair and transparent manner.

- ORS recommends the Company's use of extreme CO_2 forecasts for all future IRPs and IRP Updates be discussed further as part of the Stakeholder Working Group.

- ORS recommends the Company review the fixed and variable O&M assumptions for generic combined cycle and combustion turbine resources prior to filing the 2022 IRP Update, and discuss the Company's justification for the assumptions in the Stakeholder Working Group.

- ORS recommends that in all future IRPs and IRP Updates the Company consider allowing market-priced PPA solar and battery storage resources to be treated as selectable generic resource options throughout the study period rather than as one-time selections.

- ORS recommends the Company implement the PLEXOS resource optimization modeling approach beginning in the 2022 IRP Update.

- ORS recommends the use of Reliability Factors be evaluated collaboratively within the Stakeholder Working Group prior to filing the 2022 IRP Update.

- ORS recommends that the Minimax Regret analysis, and the potential benefits of other more sophisticated risk-adjusted metrics be evaluated collaboratively within the Stakeholder Working Group prior to filing the 2022 IRP Update.

- ORS recommends DESC utilize an All-Source RFP following all future IRPs and IRP Updates when actual resources need to be acquired.

- ORS recommends that the Company include the following in the transmission update section of all future IRPs and IRP updates:

    - Projects underway or recently completed;

    - A list of upcoming transmission projects and tentative anticipated completion dates; and,

  - Updates on any upcoming projects mentioned in the prior IRP. DESC should point out project additions, cancellations, and schedule adjustments, and any other significant changes to a transmission project.

- ORS recommends the Company continue to supply information on distribution resource/integrated system operation plans in all future IRPs, but include more detailed updates when the Company files Comprehensive IRPs every three years.

- ORS recommends that in addition to providing generator level performance data as an update to this IRP, the Company should also file the same data as an appendix in all future IRPs and IRP Updates.

- ORS recommends that in all future Comprehensive IRPs, the Company provide an analysis of the costs and benefits of participation in the Southeast Energy Exchange Market ("SEEM").

I. Evolution of the IRP Process in South Carolina

A. Initiation of the IRP Process

The Commission initiated a generic proceeding involving the jurisdictional Electric Utilities in June 1987 to address least-cost resource procedures based on a comprehensive planning approach.[10] The Commission first required electric utilities to file IRPs in September 1989.[11]

The Commission approved a more formal IRP process in October 1991.[12] The Commission required utilities to file detailed IRPs every three (3) years and file a short-term action plan in the intervening years. In addition to the Commission's IRP procedures, the South Carolina legislature passed a bill (Act 449) known as the South Carolina Energy Conservation and Efficiency Act of 1992, adding S.C. Code Ann. § 58-37-40.[13] The definition of an IRP adopted for use in South Carolina is reflected in S.C. Code Ann. § 58-37-10(2)

> "Integrated resource plan" means a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. For electric cooperatives subject to the regulations of the Rural Electrification Administration, this definition must be interpreted in a manner consistent

[10] Docket No. 87-223-E, Order No. 87-569, June 18, 1987.

[11] Docket No. 87-223-E, Order No. 89-521, May 17, 1989.

[12] Docket No. 87-223-E, Order No. 91-885, October 21, 1991. Attachment A to the Order contained the detailed IRP requirements. Another Order granting clarification and modification was issued on November 6, 1991 (Order No. 91-1002).

[13] www.scstatehouse.gov/billsearch.php?billnumbers=1273&session=109&summary=B

with any integrated resource planning process prescribed by Rural Electrification Administration regulations.

Until 1998, utilities followed the IRP requirements established by the Commission's 1991 order. On February 3, 1998, Duke Energy filed a petition to modify the IRP requirements, which led the Commission to re-evaluate its IRP procedures.[14] On July 2, 1998, the Commission issued Order No. 98-502, which established a simplified set of IRP requirements based on what the Commission observed at the time to be "the changing nature and deemphasis of Integrated Resource Planning."[15] More recently, the state legislature passed Act 62 also known as the Energy Freedom Act of 2019, which addressed many issues associated with utility planning, including updating and re-emphasizing IRP requirements.[16]

B. Act 62 IRP Requirements

Act 62 was signed into law in May 2019. Act 62 updated Section 40 by changing some requirements and adding others that affected not only the electric utilities, but also the Commission, ORS and the State Energy Office ("SEO"). Act 62 applies to all electric utilities in South Carolina.

Section 40 now requires electric utilities to file IRPs that provide more detailed information to the Commission and other parties, and to post the IRPs on both the Commission and utility's websites. Electric utilities are required to file IRPs at least every three (3) years, and to file annual updates with specific information in the intervening years.[17] Section 40(B)(1) sets forth the required information and Section 40(B)(2) sets forth the additional optional information.

Section 40 now requires the Commission to establish a proceeding to review each electric utility's comprehensive IRP that is filed every three years. Interested parties are permitted to intervene and submit discovery. Section 40(C)(1) states the new requirements are intended to allow interested parties to obtain "evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plan."

Sections 40(C)1 and (C)2 state the Commission shall issue a final order within 300 days approving the utility's IRP as is, if the Commission "determines that the proposed

[14] February 3, 1998. Docket No. 87-223-E, Order No. 98-502, July 2, 1998.

[15] Docket No. 87-223-E, Order No. 98-150, February 25, 1998.

[16] Act 62 became effective on May 16, 2019.

[17] S.C. Code Ann. § 58-37-40(D)(1).

integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." However, if the Commission finds that the IRP does not meet that standard, then the Commission is required to either order the utility to make specific modifications to the IRP or reject the IRP entirely. If the Commission makes one of these determinations, Section 40(C)(3) provides procedures and a timeline that requires the utility to resubmit the IRP and ORS to review the revisions and report its findings to the Commission. Then, the Commission "at its discretion may determine whether to accept the revised integrated resource plan or to mandate further remedies that the Commission deems appropriate."

Section 40(C)2 directs the Commission to consider seven (7) factors as it evaluates whether the IRP is "the most reasonable and prudent means of meeting energy and capacity needs" and determine whether the IRP should be accepted, modified or rejected.

Section 40(D)1 discusses the requirements for IRP updates that are to be filed during the two (2) intervening years between when comprehensive filings are to be made. Section 40(D)2 discusses the procedure for reviewing annual updates, which is different than for the comprehensive filing that utilities must make every three (3) years. For the annual updates, ORS is required to review the utility's filing and submit a report to the Commission containing a recommendation concerning the reasonableness of the annual update. The Commission then must decide if it will "…accept the annual update or direct the electrical utility to make changes to the annual update that the commission determines to be in the public interest."[18]

In the October 13, 2021 Amended Scheduling Order in this proceeding, the Commission voted to provide all other parties of record the opportunity to file comments on DESC's 2020 IRP Update within thirty days of ORS's report, and to allow all parties of record to file responsive comments within another thirty days. The Commission further clarified that a hearing could be requested by any party of record and that the Commission could set the docket for hearing.

[18] S.C. Code Ann. § 58-37-40(D)(2).

C. Background of DESC IRP Proceeding

DESC 2020 IRP

Pursuant to Section 40, DESC filed the 2020 IRP with the Commission on February 28, 2020 in Docket No. 2019-226-E.[19] In the IRP, the Company modeled eight (8) different resource plans ("RP") that reflected a range of resource additions and retirements to meet the utility's resource needs over fifteen (15) year study period (2020-2034).[20] DESC also conducted scenario analysis considering various sensitivities of DSM, natural gas prices, and CO_2 prices. Furthermore, DESC modeled five (5) additional RPs and sensitivities created using assumptions provided by the South Carolina Solar Business Alliance ("SCSBA").[21]

The Company identified RP2 as the preferred least-cost plan.[22] RP2 assumed that there would be no early retirements of existing resources and no new resource additions until 2035, including new solar resources beyond the additions in 2020 and 2021 that are under contract. It further assumed that the new resource additions from 2035 and beyond would be natural gas-fired ICTs.

On July 10, 2020, ORS filed a report reviewing DESC's IRP and assessing the compliance with the statutory requirements in Section 40(B)(1) and (2). Through the review, ORS determined that the Company complied with the requirements of Section 40 but identified numerous flaws and provided near and long-term recommendations to be addressed by the Company. Several intervenors in the proceeding proposed similar and additional modifications to DESC's IRP in their respective testimonies.

At the time the Company filed Rebuttal Testimony in Docket No. 2019-226-E on August 28, 2020, it included a revised 2020 IRP ("IRP Supplement") incorporating numerous corrections and adjustments to the original filing, but it maintained the selection of RP2 as the least-cost resource plan.[23] ORS reviewed DESC's IRP Supplement and determined the Company incorporated all but two of ORS's near-term recommendations. In addition, ORS continued to stress that the Company should address ORS's long-term recommendations as soon as possible, but not later than the next comprehensive IRP in

[19] Docket No. 2019-226-E.

[20] DESC 2020 IRP, p.40.

[21] *Id,* Appendix, A.

[22] Direct Testimony of Eric Bell, Docket No. 2019-226-E, June 4, 2020, p.25, l. 20.

[23] Rebuttal Testimony of Eric Bell, Docket No. 2019-226-E, August 28,2020, p.33, l. 5.

2023. However, several intervenors made additional recommendations and recommended the Commission reject DESC's 2020 IRP and IRP Supplement.

Following the hearing, pursuant to Section 40(C)(1), the Commission rejected DESC's 2020 IRP and required the Company to refile the 2020 IRP with modifications.[24]

DESC Modified 2020 IRP

Pursuant to Order No. 2020-832 and Section 40(C)(3), the Company filed the Modified IRP with the Commission on February 19, 2021. In the Modified IRP, the Company modeled six (6) additional RPs for a total of fourteen (14) under the new resource cost assumptions and other requirements from Order No. 2020-832. These were presented across twenty-seven (27) scenarios based on three (3) sensitivities—natural gas prices, CO_2 prices, and DSM. DESC also incorporated a Short-Term Action Plan as directed by the Commission.

In the Modified IRP, DESC identified the preferred plan as RP8 in contrast to the selection of RP2 as the preferred plan that it had previously made. This selection was based on eight (8) metrics representing cost effectiveness, carbon reduction, renewable generation, fuel price resiliency, reliability, supply diversity, and risk analysis.[25] RP8 assumed the retirement of DESC's coal units Wateree and Williams in 2028, and added new solar and battery storage, ICTs, and Combined Cycle ("CC") units to meet capacity needs. The Company also indicated that the "expected case scenario" (unlike the "base case scenario" in the original IRP) would include the high DSM, \$12/ton CO_2, and low natural gas price assumptions.[26]

As required by Section 40(C)(3), ORS filed a report on the sufficiency of DESC's Modified IRP on April 20, 2021.[27] With one exception, ORS determined that the Company met the requirements specified in Order No. 2020-832. Additionally, the intervenors filed comments in response to the Modified IRP, and on May 24, 2021, DESC filed a responsive letter to the ORS report and intervenors' comments addressing ORS's issue.

In accordance with Section 40(C)(3), the Commission was required to issue a determination within sixty (60) days of the ORS report on whether to accept the Modified IRP or require additional changes. On June 18, 2021, the Commission issued Order No.

[24] Docket No. 2019-226-E, Order No. 2020-832, December 23, 2020.

[25] Modified 2020 IRP, p.48.

[26] *Id* at 75.

[27] ORS's "Review of Dominion Energy South Carolina, Inc. Modified 2020 Integrated Resource Plan, Docket No. 2019-226-E, Pursuant to Order No. 2020-832"

2021-429 accepting DESC's Modified IRP while issuing additional instructions for future IRPs and IRP Updates.[28]

Tables A-1, A-2, A-3, and A-4 in Appendix A of this report summarize the requirements for the DESC 2021 IRP Update specified in Commission Order Nos. 2020-832 and 2021-429. Each Table cross-references the requirements to the corresponding Section of the Commission Orders, including the Orders' Findings of Fact, Evidence and Evidentiary Conclusions, and Ordering Paragraphs sections. Tables A-1 through A-4 indicate that 28 actions must be performed in the 2021 IRP Update to meet the requirements of Order Nos. 2020-832 and 2021-429. The specific purpose of Tables A-1 through A-4 are as follows:

Table	Purpose
A-1	New requirements identified by Order No. 2021-429 (issued after the Modified IRP).
A-2	Requirements identified by Order No. 2020-832 (issued after the 2020 IRP), but revised by Order No. 2021-429.
A-3	Requirements identified by Order No. 2020-832.
A-4	Requirements identified by Order Nos. 2020-832 and 2021-429 for Stakeholder Engagement.

As required by Section 40(D)(1), the Company filed the 2021 IRP Update on August 17, 2021. While the statute does not specify a timeline for the ORS review, the Commission ordered that ORS had one-hundred and twenty (120) days to review and file a report regarding the 2021 IRP Update.[29] This report contains the results of ORS's review of the 2021 IRP Update.

D. ORS Approach to Performing the Review of the IRP 2021 Update

ORS conducted a review of the Company's 2021 IRP Update in accordance with Section 40(D)(2) which states:

> The Office of Regulatory Staff shall review each electric utility's annual update and submit a report to the commission providing a recommendation concerning the reasonableness of the annual update. After reviewing the annual update and the Office of Regulatory Staff report, the commission may accept the annual update or direct the electrical utility to make changes

[28] Docket No. 2019-226-E, Order No. 2021-429, June 18, 2021.

[29] Order No. 2021-685.

> to the annual update that the commission determines to be in the public interest.

The ORS objective is to evaluate the Company's compliance with the Commission Order Nos. 2020-832 and 2021-429, and the requirements outlined by Section 40(D)(1), which states:

> An electrical utility shall submit annual updates to its integrated resource plan to the commission. An annual update must include an update to the electric utility's base planning assumptions relative to its most recently accepted integrated resource plan, including, but not limited to: energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, changes to projected retirement dates of existing units, along with other inputs the commission deems to be for the public interest. The electrical utility's annual update must describe the impact of the updated base planning assumptions on the selected resource plan.

ORS reviewed DESC's IRP 2021 Update, along with additional information obtained from the Company through discovery, including the Company's input assumptions, modeling methodologies, and analysis of results. ORS also tracked all requirements as prescribed by the Commission for the IRP 2021 Update in both Order Nos. 2020-832 and 2021-429. Table 1 lists the Commissions requirements that must be addressed in the Company's annual update. Table 1 indicates that the Company was required to address 28 requirements in total. Note that Tables A-1, A-2, A-3 and A-4 in Appendix A cross references these items to their respective Findings of Fact included in Commission Order Nos. 2020-832 and 2021-429.

Table 1

Item	Summary of Commission Requirements	DESC 2021 IRP Update Section	ORS 2021 IRP Update Section	Included? (Y/N)
1	Provide Details on CT Plan	Executive Summary (p.7); The CT Replacement Plan (pp.19-22)	CT Replacement Plan Details	Yes
2	Adjust Reliability Factors to Match Joint Intervenor Comments	Resource Plan Analysis (p.32); p.54-58	Reliability Factors	Yes
3	Adhere to Order No. 2020-832 for Minimax Regrets and Cost Range analysis in addition to using the "average ranking"	Resource Plan Analysis (p.32); p.39-40; Mini-Max Regret & Cost Range Analysis (p.59);Resource	Cost Range and Minimax Regret Analysis	Yes

Item	Summary of Commission Requirements	DESC 2021 IRP Update Section	ORS 2021 IRP Update Section	Included? (Y/N)
	approach in Simple Quantitative Risk Analysis	Plans Ranked Across All Scenarios (p.60-61)		
4	Develop and Implement an All-Source Procurement Plan in future IRPs	p. 10	All Source Procurement Plan	Yes
5,6	Utilize LCSE in Market Potential Study and in Developing future IRPs and Present Realistic and Levelized DSM Costs	IRP Stakeholder Working Group Meetings (p.12, 15-16); Resource Plan Analysis (p.32)p.15; Levelized Cost (p.41)	Levelized Cost of Saved Energy	Yes
7	Utilize Marginal Line Losses In Calculation for Avoided Costs in Market Potential Study	IRP Stakeholder Working Group Meetings (pp. 12, 15-16); Resource Plan Analysis (p.32)	Line Losses	Yes
8	Evaluate near term solar and storage additions	Included in RP7 and RP8 scenarios	Near Term Solar and Storage	Yes
9	Use "cost effective, reasonable and achievable" as the standard for evaluating DSM measures	IRP Stakeholder Working Group Meetings (pp. 12, 15-16); Resource Plan Analysis (p. 32)	DSM Standard – "Cost Effective, Reasonable and Achievable"	Yes
10-19	Include all requirements as outlined in Order No. 2020-832 (for Modified 2020 IRP)	Included throughout, and all requirements satisfied. See Table A-3 for details.	Included throughout	Yes
20	Include Load Forecasts and Integration of EE impacts	p.8; Load Forecast (p.31)	Load and Energy Forecast	Yes
21	Adopt and Implement the Use of Capacity Expansion Software	Short Term Action Plan Update (p.68-72)	Model RP7a, RP7b and RP8a Scenarios	Yes
22	Perform a Comprehensive Coal Retirement Analysis	p.14, 17-19 (Missing from Appendix A)	Model RP7a, RP7b and RP8a Scenarios	Yes
23	Include DSM and Purchased Power as Resource Options	To be evaluated after full implementation of the PLEXOS resource optimization software.	Stakeholder Process	Yes
24	Include Solar PV's Winter Capacity in 2021 and 2022 IRP Update	p.13, 16; IRP Stakeholder Working Group Meetings (p. 15-16); Resource Plans (p. 35); Appendix A p. 75,77	Solar Capacity Value	Yes

Item	Summary of Commission Requirements	DESC 2021 IRP Update Section	ORS 2021 IRP Update Section	Included? (Y/N)
25	Implement the Cost Range and Minimax Regret Analyses & Consider More Risk-Adjusted Metrics	Mini-Max Regret (p.59); Cost Range Analysis (p.59); Resource Plans Ranked Across All Scenarios (pp.60-61)	Cost Range and Minimax Regret Analysis	Yes
26	Work with Stakeholders to Develop a wide but plausible range of Load Forecasts and Ensure that Cost Modeling Captures each resource plan's capabilities	Load Forecast (p.31)	Load and Energy Forecast	Yes
27	Include Comprehensive Evaluation of the Cost Effectiveness and Achievability of Higher Levels of Savings as outlined by Witness Hill	IRP Stakeholder Working Group Meetings (p.15); Demand Side Management Assumptions (p.37); Short Term Action Plan Update (p.70)	DSM Reasonableness	Yes
28	Include Load Forecasts and Integration of EE impacts	p.8; Load Forecast (p.31)	Load and Energy Forecast	Yes

II. Compliance with Requirements of Section 40

This section of the Report first addresses the Company's compliance with the specific information requirements listed in the statute. The 2021 IRP Update is required to update the base planning assumptions from the Modified IRP and analyze the impact on the RP selected in that IRP.[30] As such, the 2021 IRP Update must update the Company's modeling and demonstrate that RP8 (the selected RP in the Modified IRP) continues to meet the standards set forth in Section 40(B). If the updated modeling shows that RP8 no longer meets these standards, DESC must select a different RP that meets the most reasonable and prudent standard set forth in Section 40(C)(2). In DESC's 2021 IRP Update, it identified that RP8 "remains the preferred resource plan under the updated modeling."

A. Statutory Requirements in Section 40(B)(1) and (2)

The following section of this Report provides ORS assessment of the Company's continued compliance with the Section 40(B)(1) and (2) statutory requirements.

> B: An integrated resource plan shall include:
>
> (1)(a): a long-term forecast of the utility's sales and peak demand under various reasonable scenarios.
>
> (1)(b): the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios.
>
> (1)(c): projected energy purchased or produced by the utility from a renewable energy resource.
>
> (1)(d): a summary of the electrical transmission investments planned by the utility.
>
> (1)(e): several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:

[30] Section 40(D)(1).

i. customer energy efficiency and demand response programs;

ii. facility retirement assumptions; and

iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks.

(1)(f): data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio.

(1)(g): plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan.

B(1)(h): an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs.

(1)(i): a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

(B)(2): An integrated resource plan may include distribution resource plans or integrated system operations plans.

The 2021 IRP Update reasonably complies with the above requirements. However, as noted above, ORS, identified three concerns that should be addressed in this IRP, and provides some recommendations to improve future IRPs, which are addressed in subsequent sections of this Report.

B. Statutory Requirements in Section 40(D)(1)

Section 40 requires each electric utility submit an update to the base planning assumptions from the most recently accepted IRP—in this case, the Company’s Modified IRP. This requires updates to a number of planning assumptions as well as any other inputs the Commission deems to be for the public interest. Additionally, the electrical utility must describe the impact of the update on these updated planning assumptions on the selected resource plan. In this case, the selected resource plan was RP8 in the Modified IRP.

(D)(1) An electrical utility shall submit annual updates to its integrated resource plan to the commission. An annual update must include an update to the electric utility's base planning assumptions relative to its most recently accepted integrated resource plan, including, but not limited to: energy and

> demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, changes to projected retirement dates of existing units, along with other inputs the commission deems to be for the public interest. The electrical utility's annual update must describe the impact of the updated base planning assumptions on the selected resource plan.

The Company’s 2021 IRP Update reasonably complies with the above requirements. As noted above, ORS identified three concerns that should be addressed in this IRP, and provides some recommendations to improve future IRPs, which are addressed in subsequent sections of this report.

III. Evaluation of DESC's 2021 IRP Update

A. Load and Energy Forecast

As discussed in the Load Forecast section of the 2021 IRP Update, DESC did not revise the load forecast because the Company's typical practice is to update the load forecasts during the first quarter of each year for use in the planning functions performed throughout the year. Since the Modified IRP was filed in February of 2021, DESC relied on the same load forecast for the 2021 IRP Update.[31] ORS agrees this is reasonable, as it is a typical industry practice to only update load forecasts on an annual basis. ORS determined the Company's load forecast was reasonable in the recent Modified IRP, and will conduct a more detailed review when the Company next revises the load forecast.

In the 2020 IRP, ORS and other intervenors noted that while the Company developed high and low load forecast sensitivity cases, the Company did not actually use those cases in any modeling analyses that were performed. Instead, the Company performed load forecast sensitivity analyses using the high and low DSM adjustments developed as part of the DSM evaluation. This resulted in a significantly narrower range of load profiles being used in modeling analyses than the Company actually identified in the load forecast analysis evaluation.[32] The Company used the same approach in the 2021 IRP Update. The Commission addressed this in Order No. 2020-832, and required the Company by the 2022 IRP, "to work with Stakeholders to develop a wide, but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast."[33] ORS recommends the Company address this issue through the Stakeholder Working Group by the time it files the next IRP Update.

<u>Load and Energy Forecast Recommendations</u>

The Company's load forecast meets the Commission's requirements. ORS recommends the Company continue efforts to meet the Commission's requirement from Order No. 2020-832 to work with Stakeholders to develop a reasonable methodology for predicting a "wide but plausible" range of future loads for the 2022 IRP Update. The Company must begin to use that range of load forecasts in sensitivity analyses, and not just rely on the DSM adjustments to create load sensitivity cases.

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[31] DESC 2021 IRP Update, page 31

[32] ORS DESC IRP Report, page 32

[33] Order No. 2020-832, page 70

B. Reserve Margin Planning

Prior to filing the Modified 2020 IRP, the Company had a practice of using two reserve margin targets for winter and summer resource planning. In both of those seasons, the Company used a base reserve margin target and a peaking reserve margin target. The values used were established as reasonable in the Company's 2018 Reserve Margin Study.[34] The values used were:

	Summer	Winter
Base Reserve Margin Target	12%	14%
Peaking Reserve Margin Target	14%	21%

In any year, when either the summer or winter reserve margin fell below the Base Reserve Margin Target, the Company added base load resources to address the resource deficiency, and in any year when either the summer or winter reserve margin fell below the Peaking Reserve Margin Target, but was above the Base Reserve Margin Target, the Company added peaking resources to address the resource deficiency.

In order to move the Company towards a more optimal resource selection process, Order No. 2020-832 required the Company to implement a resource optimization approach that would allow any type of resource to be selected as the economically optimal resource, as opposed to following a rule that defined when either base load or peaking resources would be added.[35] The Commission required the Company to begin using the optimization approach starting with the 2022 IRP Update.

The Commission directed the Company to implement another reserve margin modeling change in the Modified 2020 IRP. The Company was instructed to identify economic resource additions only when the Peaking Reserve Margin Target drops below 21% or 14% in the winter or summer period, respectively.[36] In other words, the Company was ordered to use a single reserve margin target (Peaking Reserve Margin Target) in those seasons to decide when to add capacity, instead of using both the Peaking and Base Reserve Margin Targets. The Company complied with the requirement in the Modified IRP and relied on that same approach in the 2021 IRP Update.

Although the Company was not required to use an optimization modeling approach in the 2021 IRP Update, the Company migrated from the PROSYM Production Costing Model

[34] ORS 1-2.

[35] Order No. 2020-832, Ordering Paragraphs 7.a and 8.a.

[36] Order No. 2020-832, Ordering Paragraph 8.f.

to the PLEXOS Integrated Energy Model ("PLEXOS") for purposes of developing production cost results in the 2021 IRP Update. This is an important first step in moving to a new model and will make the Company's transition to an optimization modeling approach smoother in the 2022 IRP Update. The Company made PLEXOS available to ORS and other intervenors, which allowed ORS the ability to review and evaluate input and output details in PLEXOS. Having the ability to review and evaluate input and output details in PLEXOS will become even more important as the Company transitions to an optimization-based modeling approach.

<u>Reserve Margin Planning Recommendations</u>

The Company has not updated the Reserve Margin Study that identified the 21% and 14% winter and summer Reserve Margin Targets since the 2018 Reserve Margin Study. ORS recommends that the Company plan to update the Reserve Margin Study by the time the Company conducts the next comprehensive IRP in 2023. While ORS determined the 14% and 21% targets to be reasonable in the 2020 IRP, ORS recommends the Company update these values every few years such as when comprehensive IRP filings are made, or whenever significant changes to the system occur. For example, the Company should perform a new Reserve Margin Study in 2023 because the Company indicates it will take steps to implement a CT Replacement Plan, which will have an impact on the reliability of the system.

ORS recommends that the Company continue to provide PLEXOS to intervenors for their review and evaluation of all future IRPs and IRP Updates. Access to PLEXOS will be particularly important as the Company begins to perform resource optimization analyses.

C. Demand Side Management

The Commission issued several specific directives in Order Nos. 2020-832 and 2021-429 relating to DSM, including the need for a rapid assessment of DSM and action planning, the standard for DSM planning and achievability, the levelized cost of saved energy, levelized DSM costs, and line loss calculations. ORS reviewed DESC's 2021 IRP Update to determine if DESC complied with the Commission's requirements, and to assess the reasonableness of DESC's DSM plans relative to other utilities in South Carolina and around the country.

The Company's rapid assessment determined that achieving a 1% reduction in demand growth is possible and it has begun a DSM Market Potential Study to evaluate the cost-effectiveness and achievability of savings as high as 2%. For reference only, Duke Energy's 2020 IRPs considered 1.5% energy savings to be the base case in Duke Energy

Progress and 1.3% to be the base case in Duke Energy Carolinas, with a high and a low sensitivity applied around those values.[37]

As is detailed below, the Company is required to use 1% energy savings and to study the achievability of higher levels of savings in upcoming IRPs.

DSM Rapid Assessment and Action Plan

Ordering paragraphs 6e and 6f of Order No. 2020-832, required the Company to conduct a rapid assessment of DSM for the Modified IRP. Those paragraphs in Order No. 2020-832 stated:

> 6e. Consistent with step 1 as identified in Hearing Exhibit 16, conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up its current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and include the results of this rapid assessment in its Modified 2020 IRP. The Company will work with the DSM Advisory Group and, if desired, a contractor selected with input from the Advisory Group, in preparing this assessment
>
> 6f. Include in its Modified 2020 IRP action steps the Company will take to complete a comprehensive evaluation of the cost-effectiveness and achievability of DSM portfolios ranging from 1% to 2% savings, as identified in steps 3 through 5 of Hearing Exhibit 16.

The Company addressed the requirements in the 2020 Modified IRP and included a copy of the Rapid Assessment Report conducted by its consultant, ICF, in Appendix D of that report. Furthermore, in the Modified IRP, the Company updated the results of the 2019 Potential Study and included "the reasonable and achievable results determined under the initial rapid assessment," which became the basis for the High DSM case in the Modified IRP.[38] The Company concluded in the Modified IRP Report that "In the final analysis, ICF determined that there is a path for DESC [to] achieve 1% savings in retail sales in years 2022, 2023, and 2024."[39]

Regarding the Commission's requirement that the Company complete a comprehensive evaluation of DSM portfolios ranging from 1% to 2% savings, the Commission found in

[37] ORS Duke 2020 IRP Reports, DEP page 45 and DEC page 44

[38] Modified 2020 IRP, February 19, 2021, p. 43.

[39] *Id* at p. 43.

Order No. 2021-429 that the Company's "proposed action plan was sufficient and is designed to accomplish the goal of the related portion of Order No. 2020-832."[40]

In the 2021 IRP Update, DESC provided a status report of the Company's efforts to conduct the comprehensive evaluation of DSM portfolios,[41] including the interactions with the Energy Efficiency Advisory Group ("EEAG"). Based on consultations with the EEAG, DESC selected Opinion Dynamics Corporation as the vendor to assist in completing the market assessment portion of the 2023 DSM potential study. The Company noted that by the end of the third quarter of 2021, the Company would select another vendor to help with the "forecasting and modeling portion of the study and evaluation of programs and measures."[42] DESC intends to collaborate with the EEAG by discussing inputs, conclusions, progress, and other details regarding the 2023 filing as results become available.

ORS concluded that the Company addressed the Commission's requirements regarding the rapid DSM assessment and the Company appears to be on pace to meet the DSM action plan requirements concerning the 2023 DSM potential study.

DSM Standard – "Cost Effective, Reasonable and Achievable"

Order No. 2021-429 included an additional DSM directive regarding the standard for accepting DSM programs in DESC's portfolio, as follows:[43]

> DESC is required to use "cost effective, reasonable and achievable" as the standard going forward for evaluating the potential for higher savings portfolios in future IRPs and updates beginning with the 2021 IRP Update.

DESC describes the DSM modeling and the three DSM scenarios created in the 2021 IRP Update at page 37:

> The low DSM is equivalent to 90% of the 2019 Potential Study, which results in a reduction of 0.61% of retail sales. The medium DSM used the results of the 2019 Potential Study updated and described in Part IV of the Modified

[40] Modified IRP, Order No. 2021-429, Finding of Fact, Element 10, p. 11.

[41] At p. 70 of the 2021 IRP Update, DESC includes footnote 14 explaining that the Commission's 2020 IRP Order noted both a 2022 and 2023 deadline for completing the comprehensive evaluation of DSM portfolios. DESC stated that it would be impractical for it to complete the evaluation prior to 2023, thus it is planning for it to be included in the 2023 IRP. The Commission's Order No. 2021-429 at p. 11 confirmed the 2023 date, "The Commission finds that DESC has submitted an appropriate action plan to complete the comprehensive evaluation of DSM at the stated levels for inclusion in DESC's 2023 IRP."

[42] 2021 IRP Update, p. 70.

[43] Order No. 2021-429, Ordering Paragraph 10, p. 20.

2020 IRP, and results in a reduction of 0.73% of retail sales. The High DSM assumed DSM growth to 1% of retail sales by 2022.

The 2021 IRP Update notes that DESC relies on the 2019 Potential Study and the work conducted and approved in the Modified IRP Report.

With regard to cost effectiveness, the Company's position on the High DSM case has evolved since it filed the 2020 IRP Report on February 28, 2020. In the 2020 IRP Report, the Company asserted that the High Case is "not likely to be achievable",[44] and that "this case in no way indicates that DESC believes that it is reasonable or achievable".[45] Through the rapid assessment of DSM the Company performed with ICF in the Modified IRP, the Company was able to identify a reasonable and achievable High Case portfolio of DSM programs. The Company stated in the 2021 IRP Update that reliance on the High Case portfolio "reflects the expectation that a cost-effective suite of DSM programs can be formulated to reach a 1% reduction in forecasted load."[46]

Levelized Cost of Saved Energy

Paragraph 7 of Order No. 2021-429 required DESC to "employ a reasonable levelized cost of saved energy (LCSE) which is comparable with industry standards in conducting its upcoming Market Potential Study and in developing future IRPs starting with the 2021 IRP Update." No additional information was provided in the Commission's Order; however, the Joint Intervenor's comments to DESC's Modified 2020 IRP explained that the Company's modeled LCSE of between $40 and $57 per MWh was significantly higher than the national average of $25/MWh and the median value in the South of $22 per MWh.[47]

In the 2021 IRP Update, the Company states that it, "reviewed the LCSE presented in its Modified IRP and showed that it was calculated according to the standard definition accepted in the industry." The Company also states that it "asked the stakeholders if they disagreed [with the Company's LCSE calculations], and no changes to the LCSE were proposed."[48]

[44] ORS AIR 1-7, Docket No. 2019-226-E.

[45] Direct Testimony of Eric Bell, Docket No. 2019-226-E, June 4, 2020, p. 11, ln. 10.

[46] 2021 IRP Update, p. 32.

[47] Joint Intervenor Comments to the Modified IRP, April 20, 2021, p. 42.

[48] 2021 IRP Update, p. 15.

In ORS AIR 6-2b, ORS sought additional information as to why DESC believed its response to the Commission's LCSE reasonableness requirement in Order No. 2021-429 was indeed reasonable. The Company stated:

> DESC believes that the existing LCSE is "reasonable" because it is lower than the cost of energy. As described in the 2019 Potential Study (page 26), DESC calculated the levelized cost of energy in accordance with industry standards for the demand side management programs. "The levelized cost of energy is the net present value of the full program costs divided by the net present value of the cumulative lifetime savings from all the measures from the program. On the other hand, the annual cost of energy is the sum of all program costs divided by the incremental program savings. This means that the levelized cost takes into account all savings from the program, as well as being in real dollars, while the annual cost is in actual dollars and only considers first-year savings."

Also, the Company's response to ORS 6-2c explained the Company does have plans to discuss input assumptions "with the Energy Efficiency Advisory Group during the process of the potential study currently underway, as requested by the Clean Energy Intervenors."[49]

Based on the ORS's review of the 2021 IRP Update and the Company's response to ORS 6-2, it appears that the Company took reasonable steps to comply with the Commission's LCSE requirement in Order No. 2021-429. Also, ORS understands that the EEAG will continue to be a forum in which concerns regarding input assumptions in the potential study are addressed.

ORS recommends that the Company ensure that the LCSE assumptions are discussed collaboratively with Stakeholders as part of the EEAG, and during that process, assumptions used should be thoroughly explained and justified. All Stakeholders should be permitted the opportunity to express their views in a fair and transparent manner.

Levelized DSM Costs

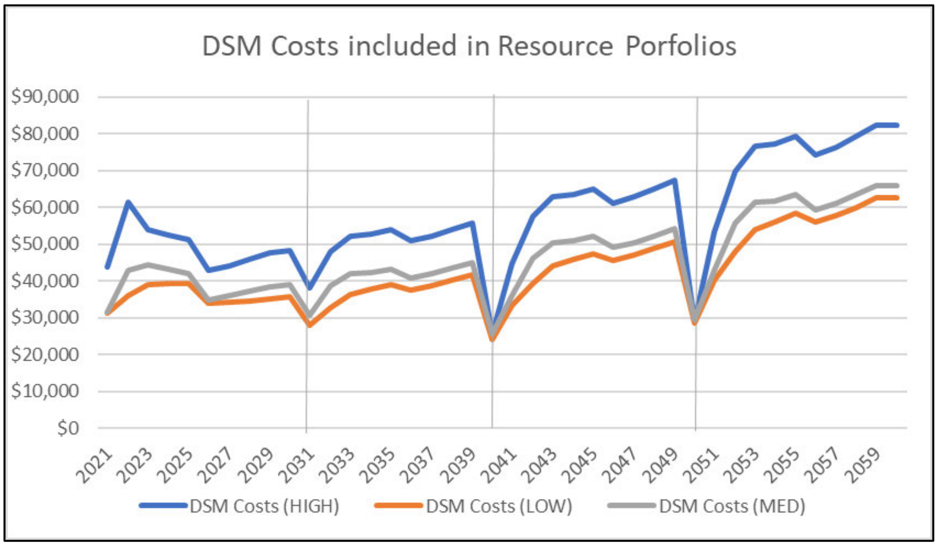
Ordering paragraph 8 of Order No. 2021-429 required DESC to, "present realistic and levelized DSM costs in all future IRPs starting with the 2021 IRP Update." No additional information was contained in the Commission's Order. However, the Joint Intervenors' comments to DESC's Modified 2020 IRP explained that "DESC modeled EE costs after 2029 in a way that produces a cost stream that has significant price swings over the

[49] *Id.*

period 2030 to 2059," because as the Joint Intervenor's explained, "every ten years the costs restart with 2021 EE costs…."[50]

The following figure demonstrates the price swings and the repeated pattern of modeled DSM costs, which were used by the Company in the 2021 IRP Update.

Figure 1 – Modeled DSM Costs



The Company did not modify its forecasted DSM costs or expected savings from the Modified IRP to the 2021 IRP Update. As a result, the forecasted DSM costs remain the same and are not levelized as shown by the periodic cost dips in 2031, 2041 and 2051.

In Appendix A to the 2021 IRP Update, the Company provided a cross reference between the Commission Order Nos. 2020-832 and 2021-429 requirements and the section and page number in the 2021 IRP Update where the Company addressed each requirement. The Company indicated that it addressed the Commission's requirement that "realistic and levelized DSM costs" be used in the 2021 IRP Update at the following locations in 2021 IRP Update Report:

> IRP Stakeholder Advisory Group Meetings (pp. 12, 15-16); Resource Plan Analysis (p.32)

However, ORS could not discern what information at those locations supported the Company's position that realistic and levelized DSM costs were used in the 2021 IRP Update. ORS recommends the Company address the potential disconnect between the

[50] Joint Intervenor Comments to the Modified IRP, April 20, 2021, p. 45.

Commission Order requiring the Company to present "realistic and levelized DSM costs" beginning in the 2021 IRP Update and the information that the Company provided in the 2021 IRP Update.

Line Losses

Ordering Paragraph 9 of Order No. 2021-429 requires DESC:

> [t]o use marginal line losses in the calculation of avoided costs and in the translation of energy savings from the Market Potential Study to energy savings in future IRP modeling beginning with the 2021 IRP update.

No additional information was contained in the Commission's Order; however, the Joint Intervenors' comments to DESC's Modified 2020 IRP identified a concern that the Company's selection of line loss factors understated the value of DSM energy savings.[51]

In the 2021 IRP Update, the Company reported that it used the marginal line loss factor for both computing avoided energy costs and capacity savings.[52] ORS confirmed that the Company's workpapers indicated that the Company also used 15.21% for computing avoided energy cost savings.[53] The Company also explained this in a Stakeholder Working Group meeting.[54]

While the Company technically complied with the Commission Order, the Company appears to disagree that the 15.21% marginal line loss factor should have been used for computing both avoided energy cost and capacity savings. The Company's 2021 IRP Update explained the Company's position as follows:[55]

> The Commission ordered the Company to use marginal line losses in computing avoided energy costs beginning with the 2021 IRP Update. The Company explained to stakeholders that, consistent with industry standards, it used the marginal line loss factor to compute capacity savings from DSM programs and the average line loss factor to compute energy savings. This was appropriate since marginal line losses capture the savings in capacity during system peaks, when capacity savings are realized, while average line losses are used to capture energy savings,

[51] *Id.* at p. 47.

[52] 2021 IRP Update, p. 16.

[53] ORS AIR 6-1.

[54] See Minutes to Stakeholder Meeting III, at p. 11, https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/2021.07.14_DESC_IRP_Advisory_Group_Session_III_Minutes.pdf. Also, see 2021 IRP Update Report at p. 16.

[55] 2021 IRP Update, p. 16.

> which occur throughout the year. Use of marginal line losses to calculate energy savings overstates DSM savings by inflating lost revenue and the shared savings incentive to be recovered under the DSM rider. This unnecessarily increases costs to all residential customers and to commercial and industrial customers who do not opt out.

It is reasonable for the Company to have used 15.21% in the calculation of both energy savings and peak demand savings, per the Commission's requirement for the 2021 IRP Update.

In a report that discusses the appropriate line loss factors that should be used in evaluating DSM entitled, "Valuing the Contribution of Energy Efficiency of Avoided Line Losses and Reserve Requirements,"[56] the authors explain that typically planners use appropriate line loss factors for evaluating avoided energy benefits, however, they often fall short in properly evaluating capacity benefits. The article explains that the energy efficiency load shape is typically consistent with the overall utility load shape and therefore, an average loss factor is appropriate for evaluating avoided energy benefits, however, peak capacity savings from energy efficiency can be greater than average savings, and therefore line loss factors used to evaluate capacity benefits should be higher than the line loss factors used to evaluate energy benefits.

The article also states:

> Energy efficiency is often credited with avoiding these average losses when regulators and utilities value efficiency investments and set the program cost-effectiveness thresholds based on avoided cost. However, the losses on utility transmission and distribution systems are not uniform through the day and the year, and the peak capacity savings from energy efficiency are typically much greater than the average savings.[57]

Throughout the article, the authors refer to the fact that marginal loss factors should be used for evaluating peak demand savings, while average loss factors should be used for evaluating energy savings.

Line loss is a technical issue that requires further discussion and clarification. ORS recommends a continued discussion within the context of the Stakeholder Working Group. In fact, Line Loss factor appears as a discussion topic on the agenda in the

[56] Jim Lazar, RAP Senior Advisor, Xavier Baldwin, P.E., Principal Engineer, Burbank Water and Power, August 2021, p. 2, https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

[57] *Id.* at p. 3.

Session VI Stakeholder Working Group Meeting, which has been scheduled for January 2022.

DSM Reasonableness

The American Council for an Energy Efficient Economy ('ACEEE") conducts yearly evaluations of statewide EE efforts, and ranks states against each other on a variety of metrics. The percentage reduction in retail energy sales is one such metric. Though the ACEEE State Energy Efficiency Scorecard ("Scorecard") compares statewide efforts, it is a useful benchmark for comparing program success of individual utilities across the country. Table 8 of the 2020 Scorecard ranks utilities' DSM results on their 2018 achieved EE savings results.[58] Table 8 shows that a 1% EE sales reduction, as DESC assumes they will achieve in this IRP, places DESC right at the average of the 52 utilities indicated in the table. The utilities with the highest energy savings in the country (energy savings over 2%) are located in states that typically have much higher energy costs than the southeast. DESC's 1% target at this time is reasonable, as it is in line with other utilities located in the southeast. Table 8 indicates that all of the southeast utilities in the table had DSM energy savings in 2018 at about the average of all of the utilities listed (1%). DESC's 1% target is a reasonable target for now, as Order No. 2020-832 requires DESC to study the possibility of achieving higher levels of energy efficiency savings in the next comprehensive IRP in 2023.[59]

DSM Recommendations

Overall, DESC's DSM modeling efforts in the 2021 IRP Update are reasonable. The Company complied with Order No. 2021-429 concerning line loss factors, the rapid assessment of DSM plans to achieve a 1% energy savings level for all DSM programs, and the objective of identifying a cost-effective, reasonable, and achievable DSM portfolio. The Company also made progress on the action plan setting up a comprehensive DSM study ahead of the 2023 IRP that will consider the possibility of achieving higher levels of EE savings in the future.

With regard to the Commission's LCSE requirement, the Company took reasonable steps to comply with the Commission's requirement. However, ORS recommends that the Company ensure that the LCSE assumptions are discussed collaboratively with Stakeholders as part of the EEAG, and during that process, assumptions used should be thoroughly explained and justified. All Stakeholders should be permitted the opportunity to express their views in a fair and transparent manner.

[58] https://www.aceee.org/research-report/u2011

[59] Order No. 2020-832, p. 76.

Finally, ORS recommends the Company address the potential disconnect between the Commission Order requiring the Company to present "realistic and levelized DSM costs" beginning in the 2021 IRP Update and the information that the Company provided in the 2021 IRP Update.

D. Natural Gas Price and CO_2 Forecasts

Commission Order No. 2020-832, Ordering Paragraph 6.b.vii, requires the Company to:

> Rerun its production cost modeling using the Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") low, reference, and high gas prices described by SCSBA Witness Sercy in his direct testimony, and using the AEO High CO_2 case, also as detailed in Mr. Sercy's direct testimony.

The Company addressed the requirement in the Modified IRP using the latest available forecast at the time, the AEO 2020 for gas prices, and the Company modeled three (3) CO_2 price cases, a low $0/ton CO_2 case, a medium $12/ton CO_2 case (starting in 2030, 10% escalation), and a high $35/ton CO_2 case (starting 2021, 7.5% escalation). In the 2021 IRP Update, the Company used the same approach, including using the same CO_2 assumptions, however, it updated the AEO gas price forecasts to use the 2021 AEO forecast instead of the 2020 forecast.[60]

Although DESC complied with each of the Commission's requirements regarding CO2 forecasts, the Company did not accept that the $35/ton CO_2 forecast the Commission ordered DESC to use was reasonable. In the 2021 IRP Update, the Company contends that:

> The $35/ton and 7.5% escalation case does not represent a likely CO_2 price forecast. Escalation at 7.5% results in a CO_2 price of $285 per metric ton by 2050. Under the $35/ton scenario which begins in 2021, costs to DESC customers would be over $400 million this year and could increase to $2 billion per year by 2050 for CO_2 alone. This level of customer impact is indicative of impacts that would be experienced throughout the economy from CO_2 prices at this level; therefore, imposing CO_2 prices of this magnitude are not reasonably foreseeable.[61]

Based on a review of the Company's natural gas price forecast workpapers, ORS determined that the Company complied with the Commission's order to use EIA AEO low, reference and high gas prices. In comparison to other forecasts that are publicly available,

[60] 2021 IRP Update, pp. 37-38.

[61] 2021 IRP Update, p. 38.

DESC's forecasts appear to be reasonable. The figure below compares DESC's EIA based reference forecast to recent forecasts from Avista,[62] Detroit Edison, Duke Carolinas,[63] Kentucky Power,[64] Northwest Power and Conservation Council,[65] Southern Company,[66] Tucson Electric,[67] Virginia Power[68] and Xcel Upper Midwest.[69]

[62] Avista 2021 IRP, Appendix A, Natural Gas Price Forecast, August 6, 2020, pg. 10 https://www.myavista.com/about-us/integrated-resource-planning. See Appendix A link. Using Average, 25th and 95th percentiles.

[63] Duke Energy Carolinas 2020 IRP, Figure A-2, pg. 158. https://www.desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/irp/202296/dec-2020-irp-full-plan.pdf?la=en&rev=907071cc4dc4651b25ab93ca6f3d8f0

[64] Kentucky Power 2019 IRP, pg. 99. https://www.psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/1220201920748/KPCO_2019_IRP_Volume_A_Public_Version.pdf.

[65] Northwest Power and Conservation Council, 2021 Power Plan. https://nwcouncil.app.box.com/s/94w5ii097x0uoc871yoxtl76ehslc9p1. See 2021 PowerPlan_GasModNorthwest.xlsx

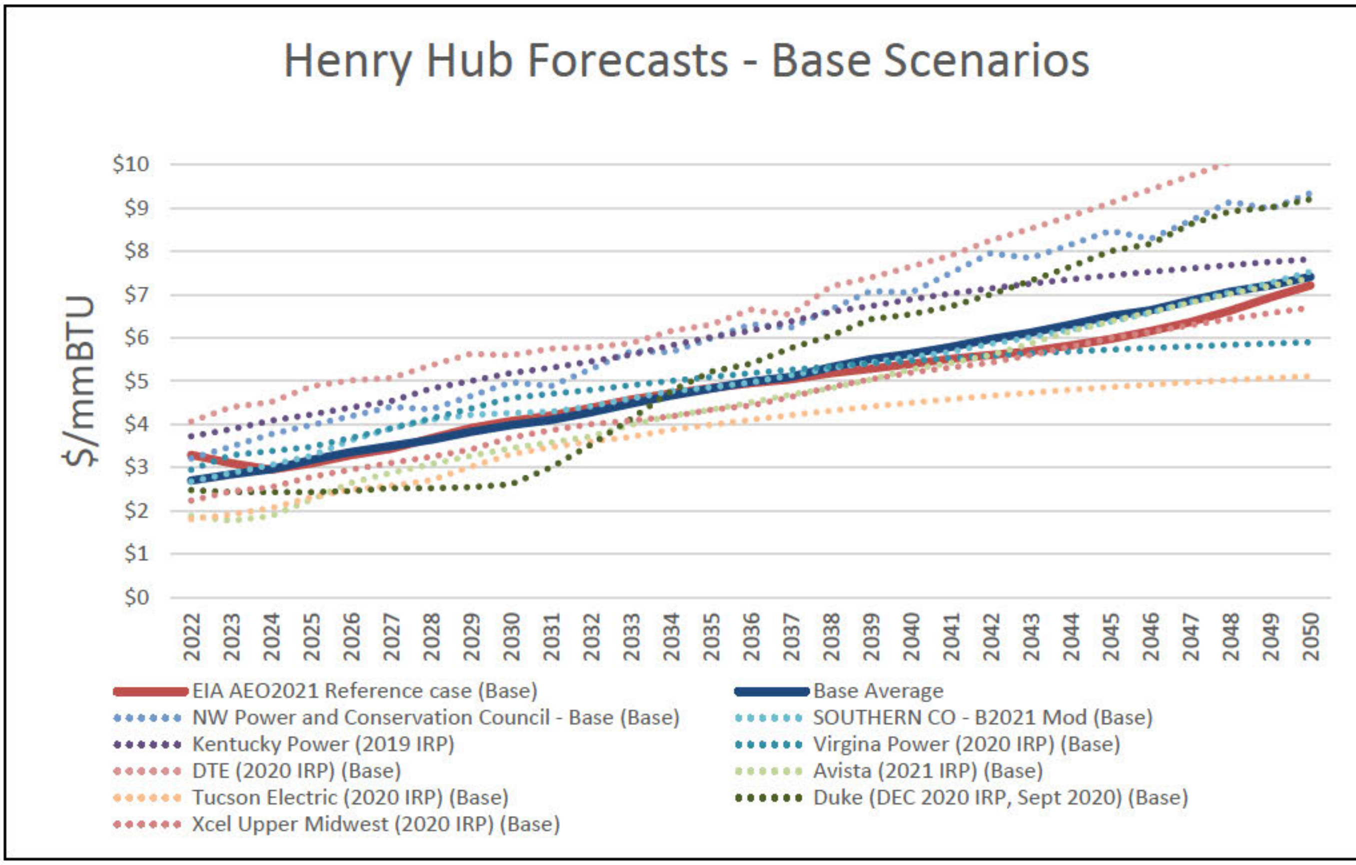
[66] Southern Company B2021 Gas Price Forecast. Downloaded from the 25th Vogtle Construction Monitoring proceeding.https://services.psc.ga.gov/api/v1/External/Public/Get/Document/DownloadFile/187253/69053. See STF-217-11d.

[67] Tucson Electric Power 2020 IRP, pg. 131. https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf

[68] Virginia Electric Power Company 2020 IRP, Appendix 4O, pg. 4. https://www.dominionenergy.com/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509

[69] Xcel Upper Midwest 2020 IRP, pg. 48. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF0AB0573-0000-C11C-B7B2-2FA960B89BD1%7D&documentTitle=20206-164371-01

Figure 2 – Gas Forecast Comparison (Base Case)



<u>**Natural Gas and CO2 Price Forecast Recommendations**</u>

The Company should continue to update natural gas forecasts utilizing recent market data and study information as available. Regarding CO_2, the Company's concern that a \$35/ton CO_2 forecast may be extreme may be legitimate. However, ORS is aware that extreme CO_2 forecasts are considered by modelers for planning purposes in the industry. ORS recommends that extreme CO_2 forecasts be discussed as part of the Stakeholder Working Group.

E. Existing System Resources

The Company operates a diverse fleet of generating units to serve customer load, including sixteen (16) CT units totaling 399 MWs, four (4) coal units totaling 1,709 MWs, seven (7) CC Units totaling 2,325 MWs, one (1) Nuclear unit, which the Company's two-thirds ownership stake totals to 662 MWs, two (2) major hydro units plus other smaller hydro units including the Fairfield pumped storage, which together total 800 MWs, and several solar units amounting to 876 MWs of nameplate capacity (expected load carrying capability value of 103 MWs).[70] As of this IRP, the Company does not have any battery storage resources.

The following table and graph are based on information the Company supplied to show the sources of capacity and energy used to serve load in 2020.[71]

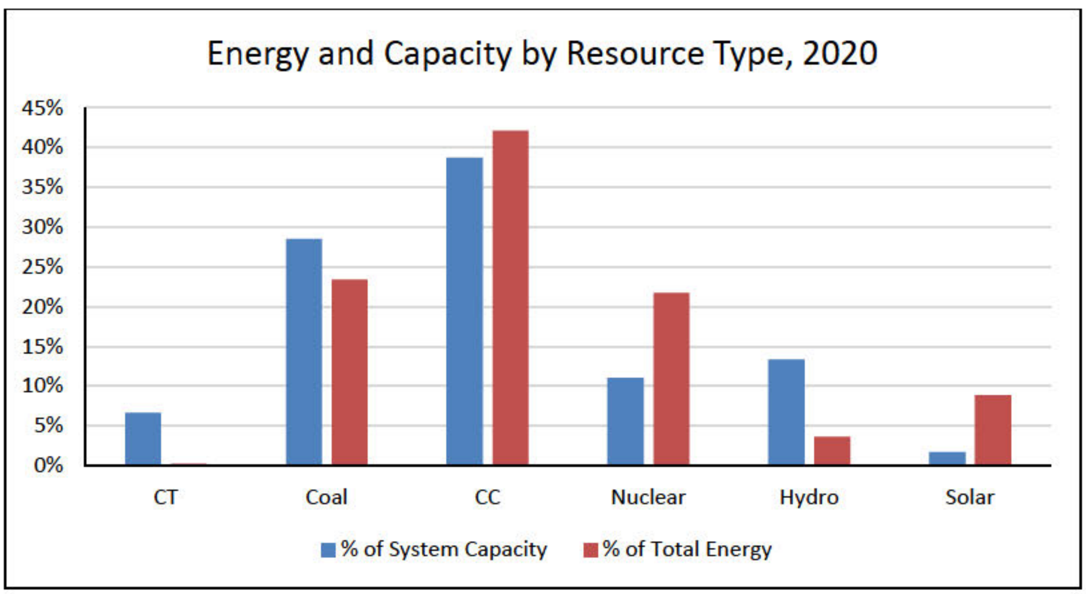
Table 2

Sources of Capacity and Energy to Serve DESC's Load in 2020

Resource	% of System Capacity	% of Total Energy
CC	39%	42%
Coal	28%	23%
Hydro	13%	4%
Nuclear	11%	22%
CT	7%	0%
Solar	2%	9%

Figure 3

Sources of Capacity and Energy to Serve DESC's Load in 2020



[70] 2021 IRP Update, pp. 9 and 26-28, and DESC's responses to ORS AIRs 1-6 and 1-14. Capacity ratings are winter ratings

[71] *Id.*

CT Replacement Plan Details

Order No. 2021-429, Ordering paragraph 3, stated the following concerning DESC's CT Replacement Plan:

> ….DESC omitted any substantive details of the CT Plan in its Revised Modified 2020 IRP and DESC did not include the CT Plan in its revised modeling. DESC is therefore ordered to provide these updates in its 2021
>
> IRP Update.

In response, DESC included a section in the 2021 IRP Update entitled "The CT Replacement Plan."[72] This section details the Company's reasons for currently operating sixteen (16) simple cycle CT resources, which includes the need for peaking resources, operating reserves, resources to provide local voltage support, resources that can restart other generating units in the event of a system emergency, which resources are referred to as "black-start units," and emergency back-up support for the Summer Nuclear Unit and the Department of Energy's Savannah River Site. DESC explained that given the age and condition of thirteen of the units, the Company intends to replace nearly all CT resources located at the Parr, Coit, Urquhart, Williams (Bushy Park), and Hardeeville Stations. The Company further explained the reasons for wanting to replace the units as follows:

> Most of these CT are more than 50 years old. Because of their fast-start capabilities and operational flexibility, these units have been placed under increasing operating pressure to follow loads in response to the intermittency of solar generation which varies hour to hour depending on localized cloud cover and weather conditions. Many of these CTs were originally constructed for intra-day peaking use on an infrequent, seasonal basis, during times of significant capacity shortfalls on the system, and for standby black-start capabilities. They were not designed to be started up and run daily to respond to solar intermittency and system balancing as required today. Their age, coupled with their challenging operational profile, has resulted in maintenance and reliability issues

The Company states that three (3) of the thirteen (13) units are currently inoperable and would require investments that the Company has decided would be imprudent given the age of the units. As a result, the Company devised a plan to replace ten (10) of the CT units, as well as one (1) natural gas-fired steam turbine unit, with five (5) new aeroderivative CT units. The Company proposed to retire the other three (3) CT units with no replacement.

[72] 2021 IRP Update, pp. 20-23.

The Company's 2021 IRP Update provides the name, locations, and capacities of the thirteen (13) retiring units, expected characteristics of the five (5) replacement resources, and a timeline of expected retirements and replacement units. The Company also responded to ORS's data requests for further details on the CT plan, including heat rates, emission characteristics, cost assumptions and timing of implementation.[73]

The Company explained that the regulatory process of retiring the units is currently underway and that the units will be replaced with what it believes will be "….state-of-the-art, fuel-efficient aeroderivative CTs with best-in-class control systems, fuel efficiency and air emission controls…."[74] DESC intends to have the units in service by the winter of 2023, which is an aggressive schedule. DESC also noted that the CTs will be capable of burning up to 30% hydrogen fuel and later could be upgraded to burn 100% hydrogen fuel.[75]

DESC did not perform any analysis of the CT Replacement Plan in the 2021 IRP Update, such as to assess the economic benefit of replacing the CTs, as the Company has already decided on a replacement plan, and therefore, the Company simply locked in the retirements and the CT replacements in each case it modeled in the IRP.

The Company explained the current status as of the filing of the 2021 IRP Update on August 17, 2021 was that it began competitive procurements to identify appropriate technologies and suppliers in 2020, which process concluded in 2021 after the Company filed the Modified IRP on February 19, 2021. The Company filed a request in Docket No. 2021-93-E on March 10, 2021, seeking Commission approval of the CT Replacement Plan.

Based on filings made in Docket No. 2021-93-E, on July 30, 2021, the Commission issued a directive holding a proceeding on DESC's request in abeyance until 60 days after the filing of DESC's 2021 IRP Update. A Partial Settlement Agreement has been reached by the parties. The agreement was explained further in a letter that DESC's counsel filed on November 10, 2021, containing the following general provisions:[76]

- The relief the Company requested for Parr and Bushy Park should be granted.
- The Commission should hold the Company's request for the Urquhart Units replacement in abeyance until after the All Source RFP for Urquhart has been completed.

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[73] ORS AIR 1-14.

[74] 2021 IRP Update Report, p. 7.

[75] *Id.*

[76] https://dms.psc.sc.gov/Attachments/Matter/722c88dd-28fa-4d09-9ac6-f6064e1e032f

- DESC will work collaboratively with Intervenors to develop the All Source RFP.

On December 1, 2021 the Commission issued a directive holding the remaining procedural schedule in abeyance until further ordered by the Commission. Commission directive 2021-782 also continued the hearing, which was scheduled for December 9, 2021, so that DESC can issue the All Source RFP related to the Urquhart Unit replacement.

The Company embedded the retirements and the CT replacements per the proposed CT Replacement plan in the 2021 IRP Update. The Company has reasonably met the Commission's requirement to provide substantive details on the state of the proposed CT replacement plan in the 2021 IRP Update

<u>Existing System Resources Recommendations</u>

There are no recommendations regarding Existing System Resources.

F. Generic Resource Options

ORS evaluated the Company's modeling of generic resource options in this IRP and reviewed the Commission specific directives regarding generic resources in Order Nos. 2020-832 and 2021-429. The Commission Orders include directives about the Company's assumptions regarding solar and battery PPA costs and cost escalation, solar integration costs, and ICT costs.

ORS compiled the following tables of generic resource costs for CC, CT, solar, and battery resources to compare to DESC's assumptions. The tables include comparisons to generic costs from EIA, NREL, and Lazard (Figure 4). The Company's assumptions were obtained from information contained in the Company's PLEXOS database and results, and workpapers supplied in discovery responses.[77]

[77] The DESC capacity size, CAPEX, Variable O&M, Fixed O&M, Heat Rate, and Capacity Factor figures come from PLEXOS and are confidential.

Figure 4

Combined Cycle ("CC")

	Size (MW)	Lead Time (years)	CAPEX (2021 $/kW)	Variable O&M (2021 $/MWh)	Fixed O&M (2021 $/kW-yr)	Heat Rate (Btu/kWh)	Capacity Factor (%)	Levelized Cost of Energy (2021 $/MWh)
EIA	1,083	3	$ 916	$ 1.97	$ 12.87	6,370		
NREL		3	$ 1,117	$ 1.86	$ 29.21	6,363		
Lazard - Low	550		$ 700	$ 2.75	$ 15.00	6,150	70	$ 45
Lazard - High	550		$ 1,150	$ 5.00	$ 18.50	6,900	50	$ 73
DESC 1x1 CC	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Combustion Turbine ("CT")

	Size (MW)	Lead Time (years)	CAPEX (2021 $/kW)	Variable O&M (2021 $/MWh)	Fixed O&M (2021 $/kW-yr)	Heat Rate (Btu/kWh)	Capacity Factor (%)	Levelized Cost of Energy (2021 $/MWh)
EIA - Aeroderivative	105	2	$ 1,125	$ 4.96	$ 17.20	9,124		
EIA - Industrial Frame	237	2	$ 681	$ 4.75	$ 7.39	9,905		
NREL		3	$ 983	$ 5.29	$ 22.36	9,515		
Lazard - Low	240		$ 700	$ 4.00	$ 7.00	9,800	10	$ 151
Lazard - High								

Combustion Turbine ("CT")

	Size (MW)	Lead Time (years)	CAPEX (2021 $/kW)	Variable O&M (2021 $/MWh)	Fixed O&M (2021 $/kW-yr)	Heat Rate (Btu/ kWh)	Capacity Factor (%)	Levelized Cost of Energy (2021 $/MWh)
	50		$ 875	$ 5.75	$ 22.75	8,000	10	$ 198
DESC - Large Frame CT	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
DESC - Aeroderivative CT	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Solar - Tracking

	Size (MW)	Lead Time (years)	CAPEX (2021 $/kW)	Variable O&M (2021 $/MWh)	Fixed O&M (2021 $/kW-yr)	Heat Rate (Btu/ kWh)	Capacity Factor (%)	Levelized Cost of Energy (2021 $/MWh)
EIA	150	2	$ 1,314	$ -	$ 16.10	-		
NREL	100	1	$ 1,408	$ -	$ 24.30	-	26	$ 39
Lazard - Low	150		$ 950	$ -	$ 13.00	-	34	$ 28
Lazard - High	150		$ 825	$ -	$ 9.50	-	21	$ 42
DESC - Solar PPA ($38.94/ MWh)	-			[redacted]	[redacted]			$ 38
DESC Company Build	-		[redacted]	[redacted]	[redacted]			

Battery Storage								
	Size (MW)	Lead Time (years)	CAPEX (2021 $/kW)	Variable O&M (2021 $/MWh)	Fixed O&M (2021 $/kW-yr)	Heat Rate (Btu/kWh)	Capacity Factor (%)	Levelized Cost of Energy (2021 $/kW-yr)
EIA	50	1	$ 1,263	$ -	$ 26.18	-		
NREL - Moderate	60	1	$ 1,372	$ -	$ 34.29	-	17	
Lazard - Low	100			$ -		-		$ 131
Lazard - High	100			$ -		-		$ 232
DESC - Battery PPA	[redacted]		[redacted]	[redacted]	[redacted]			[redacted]
DESC Company Build	[redacted]		[redacted]	[redacted]	[redacted]			

The Combined Cycle table above indicates the Company's generic resource capital cost is higher than, though conservative, compared to the alternatives shown. The CT table indicates the Company's generic resource capital costs are in line with the other alternatives. However, DESC's generic resource costs for CT fixed and variable O&M appear to be outliers compared to the other sources of data in the table. DESC's variable O&M costs appear to be somewhat low compared to the other sources of data and the fixed O&M costs appear to be high compared to the other sources of data. It is not unusual to find differences from one utility to the next in the way that fixed and variable O&M costs are represented for modeling purposes. However, given that variable O&M costs can influence the dispatch of resources, DESC should model those costs as accurately as possible, and should review the fixed and variable O&M cost assumptions for generic CC and CT resources prior to filing the 2022 IRP Update, and discuss the Company's justification for its assumptions in the Stakeholder Process.

Solar PPA Costs

The Commission found that DESC's solar PPA prices in the 2020 IRP were too high and out of line with market realities. Order No. 2020-832 required DESC to re-run the existing portfolios using $34, $36, and $38.94/MWh solar PPAs to determine the NPV savings at such levels.[78] The Company was also directed to model 400 MW of Flexible solar PPAs starting in 2023. Order No. 2021-429 added the requirement that DESC consider near-term storage and solar in the 2021 IRP Update RP8 scenarios, which included early retirement of coal units.

DESC modeled nine new resource plans based on their RP7 and RP8 portfolios. Portfolios RP7a, RP7a2, and RP7a3 moved the start date of the 400 MW solar PPA in the original RP7 from 2026 to 2023, and respectively assigned the three Commission-required PPA prices. Portfolios RP7b, RP7b2, and RP7b3 did the same except that those RPs added in 100 MW of energy storage in 2023. Portfolios RP8a, RP8a2, and RP8a3 are the same as the original RP8 but those RPs added 400 MW of solar and 100 MW of energy storage in 2023 at the respective Commission-required prices.

The Company's inclusion of solar PPAs at the Commission-required prices were utilized only for the 400 MW of solar additions in 2023. The 1,500 – 1,600 MW of later solar additions were all assumed to be self-build options.

The Company addressed the Commission's requirements regarding solar PPA cost assumptions. ORS recommends that in all future IRPs and IRP Updates the Company consider allowing market-priced PPA solar as a selectable generic resource option throughout the study period rather than as a one-time selection.

Battery PPA Costs

Witnesses in the initial 2020 IRP proceeding pointed out that the Company's battery capital cost assumptions were out of line with recent RFP results from other South Carolina utilities. Order No. 2020-832 required DESC to use the NREL ATB low storage cost, including capital and fixed O&M costs and the 22% ITC safe harbor assumption, where a nominal dollar correction is allowable.[79] The Company was directed to assume a 15-year life with no degradation, and a replacement with an equivalent resource at the lower future price when the lifespan is up. DESC modeled 100 MW of battery storage PPAs at the Commission-required prices in RP7b, RP7b2, and RP7b3 as well as RP8a, RP8a2, and RP8a3.

[78] Order No. 2020-832, pp. 49-50 and 86.

[79] Order No. 2020-832, pp. 51 and 90.

However, like the solar PPAs, DESC's additions of the lower-priced battery PPAs were limited to only the 100 MW additions in 2023. Later battery additions, such as the 700 – 900 MWs in the RP8a plans were added using higher self-build capital cost assumptions. These generic resource assumptions are not unreasonable, as seen in Figure 4 above, but the costs are higher than the Commission-required assumptions. Order No. 2020-832 has the same ambiguity over whether these lower priced PPA resources should be an option throughout the study or treated as a one-time resource.

DESC addressed the Commission's requirements regarding battery PPA cost assumptions. ORS recommends that the Company consider allowing battery PPAs in line with market projections be included as a model-selectable resource option throughout the study timeframe in all future IRPs and IRP Updates.

Solar integration costs

In Order No. 2020-832, the Commission found that DESC must "Assume integration costs of $0.96/MWh for solar PV, until an updated, Commission-approved methodology for calculating solar integration costs is available."[80] This interim value will be subject to true up per the results of the pending Integration Study.

ORS confirmed that DESC applied a solar integration charge of $0.96/MWh to the solar PPA option in PLEXOS. Like the solar and battery PPA options above, the solar integration charge is only included in the 2023 PPA options.

ORS finds that DESC has addressed the Commission's requirement to include a $0.96/MWh integration charge for their solar PPAs.

Generic resource ICT

Commission Order No. 2020-832, Ordering Paragraph 6.b.v. requires the Company to "use industry accepted ICT capital cost assumptions, such as NREL." The Company addressed this requirement in the Modified 2020 IRP using an EIA AEO cost. In the 2021 IRP Update, the Company summarized the technology costs used in a table found at page 33 of the IRP Report. The Company describes the underlying cost assumptions for the ICT resources as being unchanged from the Modified 2020 IRP, and references EIA's AEO 2020 and Dominion Energy Services - Generation Construction Financial Management & Controls as the source for the capital cost, and Handy Whitman July 2019 15-year Average – Total Plant as the source for the capital cost escalation. The costs generally align with the costs shown in Figure 4 above, with minor differences because the table on page 33 of the 2021 IRP Update shows capital costs in 2020 dollars, while

[80] Order No. 2020-832, p. 90.

Table 4 above shows capital costs in 2021 dollars. The following provides a comparison in 2020 dollars comparing the values the Company used in the 2020 IRP, the Modified 2020 IRP, and the 2021 IRP Update.

Figure 5

Comparison of DESC Capital Costs for ICT RESOURCE

	2020 IRP		Modified 2020 IRP		2021 IRP Update	
Resource	**2020 $/kW**	**Escalation**	**2020 $/kW**	**Escalation**	**2020 $/kW**	**Escalation**
ICT Large Frame (2x)	$496	3.75%	$714	3.75%	$714	3.75%
ICT Aero (2x)	$918	3.75%	$970	3.75%	$970	3.75%

The Company adequately addressed the Commission's requirements regarding the ICT Capital Cost assumptions.

Solar and Battery Cost Escalation

In the 2020 IRP, concerns were raised regarding the escalation rates that the Company used in modeling solar and battery costs. The Commission stated in Order No. 2020-832 that "…the Company implemented the two different escalation rates incorrectly which led to a spike in capital costs for both solar PV and BESS in 2031 and onwards,"[81] and it required the Company to update the escalation rates in the Modified IRP. The following figure shows a comparison between the escalation rates used by the Company in the 2020 IRP and what it is now using in the 2021 IRP Update and shows how capital costs, on a $/kW basis, increase over time.

[81] Order No. 2020-832, p. 53.

Figure 6

[redacted]

ORS concluded that DESC addressed the issue causing assumed solar and battery capital costs to spike in 2031.

Solar Capacity Value

Order No. 2020-832, ordering paragraph 6.b.iii. requires the Company to:

> Correct the incremental flexible solar PPA capacity value assumptions to reflect the ELCC value specific to the existing system penetration level of incremental flexible solar PV.

The Company addressed the requirement in the Modified 2020 IRP, using 11.8% as the capacity value for existing solar resources, and 4.25% for incremental additions, in line with the Company's study. In the 2021 IRP update, the Company provides details regarding the same calculation in Appendix C, confirming that 11.8% was used for existing, and 4.25% was used for incremental solar resources.

ORS concluded that the Company addressed the Commission's requirements regarding the Capacity Value of Solar.

Generic Resource Options Recommendations

ORS recommends that the Company should review the fixed and variable O&M cost assumptions for generic CC and CT resources prior to filing the 2022 IRP Update, and discuss the Company's justification for its assumptions in the Stakeholder Working Group.

ORS recommends that in future IRPs and IRP Updates the Company consider allowing market-priced PPA solar and battery storage as selectable generic resource options throughout the study period rather than as one-time selections.

Resource Planning

Order Nos. 2020-832 and 2021-429 required the Company to model additional resource plans, assess reliability factors, consider risk analysis, and implement an All Source Procurement Plan in future IRPs.

The following table summarizes the seventeen (17) resource plans the Company evaluated in the 2021 IRP Update.

Table 3

Resource Plans Evaluated in the 2021 IRP Update

RP ID	Resource Plan Name	Resource Plan Description
RP1	CC	An initial CC plus large frame CTs.
RP2	ICT	Large frame CTs.
RP3	Retire Wateree	Retire Wateree 2028, add CCs, plus large frame CTs.
RP4	Retire McMeekin	Retire McMeekin and Urquhart 3, add CTs.
RP5	Solar + Storage	Solar plus storage in 2026, a CC and CTs.
RP6	Solar	Add solar in 2026, and then CTs.
RP7	Solar PPA + Storage 2026	Add 400 MW solar PPA and 100 MW storage in 2026 and then CTs.
RP7a	Solar $38.94 PPA 2023	Add a $38.94/MWh 400 MW solar PPA in 2023, and then CTs.
RP7a2	Solar $36 PPA 2023	Add a $36.00/MWh 400 MW solar PPA in 2023, and then CTs.
RP7a3	Solar $34 PPA 2023	Add a $34.00/MWh 400 MW solar PPA in 2023, and then CTs.
RP7b	Solar $38.94 PPA + Storage 2023	Add a $38.94/MWh 400 MW solar PPA plus 100 MW storage in 2023, and then CTs.
RP7b2	Solar $36 PPA + Storage 2023	Add a $36.00/MWh 400 MW solar PPA plus 100 MW storage in 2023, and then CTs.
RP7b3	Solar $34 PPA + Storage 2023	Add a $34.00/MWh 400 MW solar PPA plus 100 MW storage in 2023, and then CTs.
RP8	Replace Coal	Retire Wateree and Williams in 2028. Add a CC and convert Cope to natural gas in 2030. Add storage, CTs, and solar starting in 2026.
RP8a	Replace Coal + $38.94 PPA	Retire Wateree and Williams in 2028. Add a $38.94/MWh 400 MW solar PPA plus 100 MW storage in 2023. Add a CC and

RP ID	Resource Plan Name	Resource Plan Description
		convert Cope to natural gas in 2030. Add storage, CTs and solar..
RP8a2	Replace Coal + $36 PPA	Same as RP8a but the 400 MW solar PPA is 36.00/MWh in 2023.
RP8a3	Replace Coal + $34 PPA	Same as RP8a but the 400 MW solar PPA is 34.00/MWh in 2023.

In the 2020 IRP, the Company evaluated eight (8) RPs listed in the table above, which included RP1 through RP8. Ordering Paragraph 6.a. of Order No. 2020-832, required the Company to expand the number of resource plans considered in a Modified IRP. DESC was directed to:

> Include additional candidate resource plans, representing the near-term deployment of renewables as described in the testimony of SCSBA Witness Sercy (specifically, the resource plans identified as RP7-A and RP7-B).

In the Modified IRP, DESC expanded the number of scenarios it modeled to fourteen (14) RPs, including six (6) additional modifications of RP7, which were RP7a through RP7b3. Those six modifications, as specified by SCSBA, accelerated the initial addition of solar resources from 2026 to 2023 to take advantage of federal Investment Tax Credits ("ITCs") that were anticipated to otherwise decline from 22% to 10%. Those plans modeled solar PPAs at three price points, $38.94/MWh, $36.00/MWh, and $34.00/MWH, and in configurations with and without battery storage in 2023.

While Order No. 2021-429 found that the Company's Modified IRP addressed deficiencies identified in Order No. 2020-832, the Commission also found there was room for improvement. The Company was directed to evaluate whether early retirement of coal units could be satisfied by near-term procurement of renewables. The Joint Intervenors explained this issue in their April 2021 Joint Comments in response to the Company's Modified IRP.[82]

> This means that, while RP8 is demonstrably better than the other resource plans included in the Modified IRP, neither Intervenors nor the Commission know with any certainty whether early retirement of coal assets, combined with near-term procurement of renewables, would create even more benefits for ratepayers.

[82] Joint Intervenor Comments to the Modified IRP, p. 11.

Ordering Paragraph 2 of Order No. 2021-429 directed the Company to consider the additional cases in the 2021 IRP Update. The Company expanded to model seventeen (17) RPs, including three (3) additional modifications of RP8, which were RP8a through RP8a3. The additional cases were added to assess the reasonableness of procuring near term renewables. Of the seventeen (17) cases, nine (9) have near-term solar additions and six (6) have near-term energy storage additions. The seventeen plans were evaluated under twenty-seven (27) sensitivity cases, including three (3) natural gas prices, three (3) CO_2 prices, and three (3) DSM cases.

The Company addressed the Commission’s requirements from Order Nos. 2020-832 and 2021-429 regarding modeling additional RPs. However, additional investigation of RPs is required in future IRPs. ORS recommends the Company prioritize implementation of a resource optimization modeling approach for the 2022 IRP Update.[83] There are several statements in the Company’s 2021 IRP that indicate the Company should be in a position to be able to do this, including:

- “With the assistance of personnel from other Dominion Energy subsidiaries, PLEXOS resource optimization software has been configured to model the DESC system, and the relevant data and inputs have been included. Quality assurance testing is complete and the software is ready for use.” and,

- “As reported in the June meeting of the IRP Stakeholder Advisory Group, DESC is proceeding with full PLEXOS implementation.”[84]

Also, the Commission stated a preference for use of a capacity optimization approach by the 2022 IRP Update in Order No. 2020-832 at page 16 as follows:[85]

> It is reasonable to require DESC to adopt and implement the use of capacity expansion software starting in the 2022 IRP Update, while requiring input from on the selection and implementation of the software, and ensuring that the software meets the transparency requirements of Act 62.

Reliability Factors

Order No. 2021-429 required DESC to adopt the Reliability Factors as provided in the Joint Comments of the Clean Energy Intervenors filed April 20, 2021, which expressed a concern that “…DESC’s reliability factors show clear bias towards conventional fossil technology and a misrepresentation or misunderstanding of invertor-based resources.”

[83] ORS Report on DESC 2020 IRP, July 10, 2020, see footnote 8, p. 4.

[84] 2021 IRP Update, p. 71

[85] ORS Report on DESC 2020 IRP, July 10, 2020, footnote 8, p. 4.

DESC first provided the reliability factor assessment in the Modified IRP, and it presents a table on page 55 of the 2021 IRP Update identifying the thirteen (13) Reliability Factors the Company considered. Though DESC complied with Order No. 2021-429 and adopted the Joint Intervenor's reliability factors, the Company provided additional context to support the original weightings and stated that based on the Company's engineering judgement, DESC disagreed with Joint Intervenors' reliability factor weightings. DESC further stated:[86]

> ....they weight the reliability values of solar and battery storage in ways that do not accurately reflect the operating limitation on those resources today and the practical needs of the system.

The Company and Stakeholders weight the thirteen (13) reliability factors on a scale from one (1) to four (4) for a variety of different resources. Each resource's reliability score is then calculated by summing the thirteen (13) reliability factors. For a given reliability factor the maximum score achieved by any resource is used to derive an implied reliability factor weighting. The maximum award by any resource, for each reliability factor, according to both the Company and Stakeholders is summarized below.

Figure 7

Comparison of Preferred Reliability Factors

	DESC Original Matrix		Intervenor Comments		
Reliability Factor	Max score	Implied %	Max score	Implied %	Delta
Energy Storage	1	3%	1	4%	0%
Energy Duration	4	14%	3	11%	-3%
Dispatchability	2	7%	2	7%	0%
Op Flexibility	3	10%	4	14%	4%
Coincident Peak Output	4	14%	4	14%	0%
AGC	4	14%	4	14%	0%
Fast Start	1	3%	4	14%	11%
Inertia (non-inverter)	3	10%	-	0%	-10%
VAR support	2	7%	2	7%	0%
Geographic Diversity	1	3%	1	4%	0%
Proximity to Load	1	3%	1	4%	0%

[86] 2021 IRP Update, p. 55.

Sync Cond	1	3%	1	4%	0%
Blackstart	2	7%	1	4%	-3%
Total	**29**	**100%**	**28**	**100%**	**0%**

ORS reviewed the Company's use of the reliability factors and notes that the net change in combined factors results in positive changes in reliability scores for all Resource Plans, with the RP8 plan (and variants) achieving the highest scores, and RP6 achieving the lowest.

DESC expressed concerns with the Joint Intervenors' weighting factors, though the Company acknowledged that the use of the Joint Intervenor's weightings did not materially change the outcome of the analysis. However, DESC states that because reliability is an important matter the Company intends to discuss the reliability factors in future IRP Stakeholder Working Group meetings and future IRP updates.[87]

ORS recommends that additional consideration should be given to the use of reliability factors as part of the Stakeholder Working Group. Furthermore, there may be other methods to evaluate reliability of resource plans including using a loss of load probability analysis associated with proposed RPs.

Given that the Company revised the Reliability Factor analysis and relied on the Joint Intervenor's Reliability Factor weightings, the Company's Reliability Factor analysis used in this proceeding is reasonable.

Cost Range and Minimax Regret Analysis

Order No. 2021-429 required DESC to continue to adhere to Order No. 2020-832 in using the Minimax Regret and Cost Range Analyses, in addition to using DESC's "average ranking" approach. The Commission noted that Joint Intervenor's witness Sercy stated that failing to model the various resource plans this way could have "the effect of hiding risk rather than illuminating it."[88]

DESC performed the Minimax Regret and Cost Range Analyses and presented the results of these on page 59 of the 2021 Modified IRP. DESC found that the RP7a variations performed best in the Minimax Regret analysis results, and the RP8 variations performed best in the Cost Range Analyses results. The Company notes that the high

[87] 2021 IRP Update, p. 55, and ORS AIR 1-21

[88] Order No. 2020-832, p. 64

CO_2, low gas price scenario – a scenario it considers "highly improbable"[89] – sets the Max Regret for almost all the portfolios. DESC maintains that because the Minimax Regret Analysis considers every scenario to be equally likely, "this approach gives the unlikely outcomes more influence over the results than is reasonable or appropriate."[90]

In Order No. 2020-832 the Commission found that "DESC should also consider, with stakeholder input, implementation of more sophisticated risk-adjusted metrics…"[91] However, Order No. 2021-429 required DESC to use the Minimax and cost range analyses "in its 2021 IRP Update as well as in all future IRPs."[92] Given the shortcomings of the Minimax Regret analysis like equally weighting every scenario, ORS recommends that the Stakeholder Working Group be the appropriate forum to discuss other potential methods of assessing risk in a way that avoids the shortcomings of the Minimax approach. Assuming that the Company and Stakeholders can reach a consensus about risk analysis methodologies that would be superior to the Minimax Regret analysis, ORS recommends that DESC be permitted to use the alternative agreed-upon methodologies in future IRPs.

DESC's modeling approach was reasonable, as it adhered to the Commission's requirement to include Minimax Regret and Cost Range analyses in the 2021 IRP Update.

All Source Procurement Plan

DESC was directed to "develop and implement an All Source Procurement Plan" in Order No. 2021-429, though the Commission did not establish a deadline for this to be done, other than stating "in future IRPs."[93] The Commission noted that such a process would allow independent power producers and developers to compete in a technology-neutral process, and the Commission stated that "Future DESC IRPs should recommend a portfolio of resources that best meet the needs of the DESC system using actual bid data."[94]

The Company has not yet implemented an All Source Procurement Plan, however, the Company established that it intends to do so by the 2023 IRP. The Company stated:[95]

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[89] 2021 IRP Update, p. 59

[90] *Id.*

[91] Order No. 2020-832, Ordering Paragraph 8g, p. 93

[92] Order No. 2021-429, Ordering Paragraph 5, p. 19.

[93] *Id.* at p. 19.

[94] *Id.* at p. 19.

[95] DESC 2021 IRP Update, p. 18.

> The 2023 IRP will be informed by a non-binding, indicative, all-source RFP to validate prices and market data for the potential replacement options as required by the Commission. This RFP process is planned for early 2022 to provide timely data for the 2023 IRP. Detailed transmission interconnection studies and siting proceedings before the Commission will also be required before new large-scale generation resources can be procured and constructed.

The Company also noted that non-binding RFPs may not produce reliable bids because they do not commit resource developers to provide definitive project costs.[96] ORS agrees as potential bidders may be reluctant to develop reliable bids knowing their bids would not be acted upon. However, ORS understands that the Company would attempt to design questions that would be intended to elicit reasonable responses and would compare bids against independent sources of market information.[97] ORS recommends that DESC should rely on an All Source RFP following an IRP when actual resources need to be acquired, so that the lowest cost binding bids could actually be selected for DESC's resource portfolio.

For purposes of selecting DESC's CT resources as part of the Company's CT Replacement Plan, DESC sought bids through a binding RFP process to find an Engineering, Procurement, and Construction ("EPC") contractor.

Other than the recommendation to have a binding RFP process at the time resources are actually selected, the Company's plans for an All Source RFP reasonably comply with Order No. 2021-429.

Summary of Preferred Plan

In the 2021 IRP Update, the Company determined that RP8 would continue to be the Preferred Plan. Page nine (9) of the 2021 IRP presents a table with a year by year breakdown of resource additions and retirements under RP8. In RP8, both the Williams and Wateree coal fired plants are retired in 2028, and by 2030 the Company's last remaining coal plant, Cope Station, would be converted to natural gas. In total RP8 retires 1,704 MW of coal-fired generation from DESC's portfolio. That capacity would be replaced with a 553 MW natural gas CC unit, a 523 MW gas CT resource, and a conversion of the Cope Station coal-fired unit to natural gas. Over the course of the entire

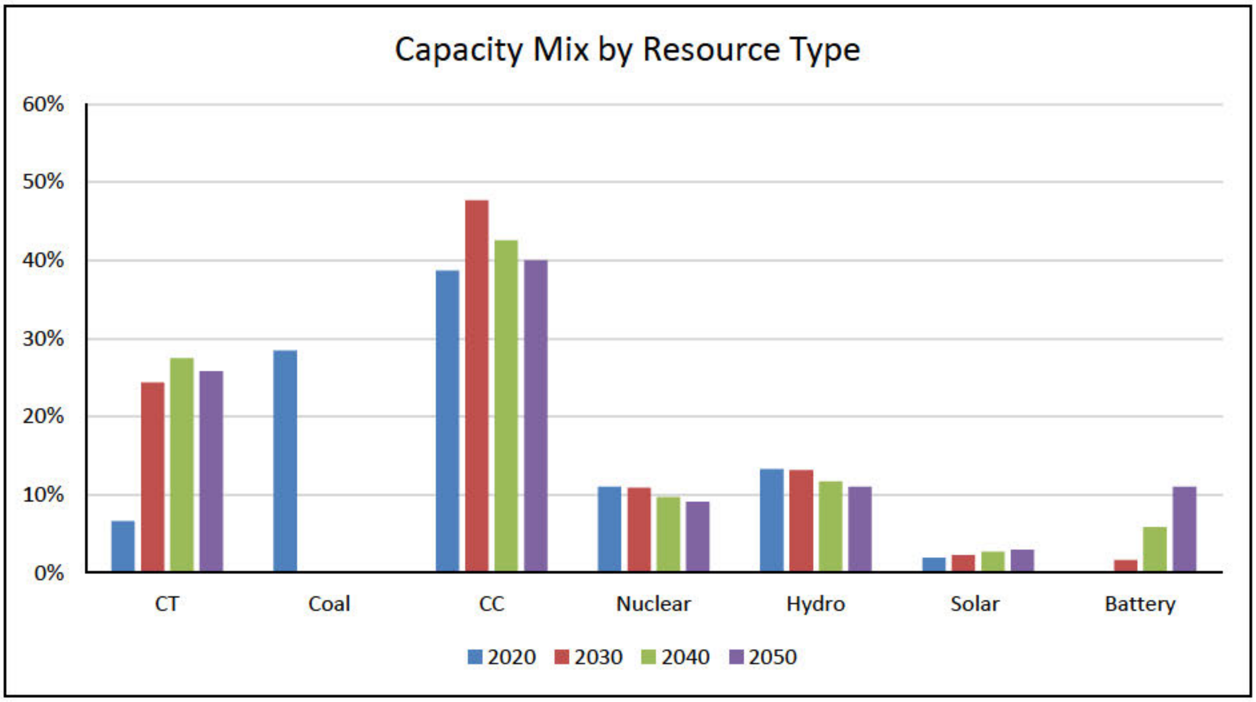
[96] *Id*. at p. 19.

[97] *Id*. at p. 19.

study from 2023 to 2049 the Company would also add an additional 393 MW of aeroderivative gas CTs, 2,000 MW of solar and 700 MW of battery storage.

The following figure shows how the Company's capacity mix would change over time under RP8. Note, solar resources in the figure are represented by their expected load carrying capability ("ELCC") value, which the Company determined is 4.25% for incremental solar additions.

Figure 8



The Company also determined that RP8a should be given additional consideration. RP8a contains the same resources as RP8, plus it add 400 MWs of solar and 100 MWs of battery storage PPAs in 2023. The Company stated this regarding the RP8a scenarios:[98]

> Modeling indicates that if the solar and battery prices assumed for the three RP8a scenarios can be achieved, adding 500 MW of near-term combined solar and battery storage assets in addition to the 1,046 MW of solar already installed could be cost effective for customers.

[98] DESC 2021 IRP Update, p. 9.

However, the Company states it is not yet willing to rely on the RP8a scenarios at this time, because as it states:[99]

> ….RP8a is based on prices for solar PPA which DESC has not encountered in the market and are further subject to question given the recent rise in costs for solar panels and associated equipment. Until the assumptions underlying the RP8a plans are validated, RP8 is DESC’s preferred plan. RP8’s superior scores on multiple key metrics clearly supports that conclusion.

As further support for the RP8 plans, the Company notes that out of 6 metrics it evaluated, Levelized costs, CO2 Emissions, 2050 Clean Energy, Average Fuel Costs, Generation Diversity, and Reliability, RP8 had the top rating under four of the metrics, including CO2 Emissions, 2050 Clean Energy, Generation Diversity, and Reliability. While these metrics may be desirable, it is important to point out that the RP8 cases will replace operating coal units with new CC and CT resources that will have to be built and will also produce CO2 emissions.

Because the RP8 cases will rely on natural gas resources that are vulnerable to gas price increases, and because the RP8 cases will require a significant amount of CT and CC resources to be built, the RP8 cases will result in higher costs than other portfolios such as the RP7 cases, which would not require the retirement of the Williams and Wateree coal units until 2044. DESC agrees that RP8 will result in higher customer rates as it stated:[100]

> Cost analyses show that RP8 and RP8a may contribute to an approximate 2.1% compound annual growth in rates through 2035, with much of the increase resulting from the new resources required to replace the energy and capacity from the Wateree and Williams units in the 2028-2030 time frame.

The Company mentions that in order for it to be able to implement resource plans that will come at higher costs to customers, there will need to be supportive Commission and South Carolina policies in place that will recognize the benefits that higher cost resource plans may bring such as lowering carbon emissions.

[99] *Id.* at p. 63.

[100] 2021 IRP Update, p. 9.

ORS does not object to the Company's position that RP8 will be further evaluated in the retirement analyses currently taking place.

ICT Generation

In examining the Company's PLEXOS model, ORS noticed that the Frame ICT capacity factors were higher than normally expected for ICT units. ORS examined the ICT output heat rates, which appeared to be out of line with the heat rates normally expected for ICT units.

ORS notified the Company of this issue and discussed the discrepancy on a conference call. The Company believes the discrepancy is a PLEXOS model related issue and is discussing the issue with Energy Exemplar. The Company believes the difference is a minor issue that should not materially impact the final costs or rankings of the various expansion plans given the scope of the IRP.

ORS agrees that this issue is not likely to cause a significant impact on the final costs of various portfolios, especially considering that these units are typically only built in later years of the study period and in relatively similar quantities across most model runs. Still, ORS recommends that in this IRP the Company discuss further the impacts ICT resources had on the Company's results, and explain the materiality of the impacts on the final costs and relative portfolio rankings.

Resource Planning Recommendations

ORS offers the following recommendations regarding resource planning:

- The Company should implement the PLEXOS resource optimization modeling approach beginning in the 2022 IRP Update.
- Further consideration of the use of Reliability Factors should be evaluated collaboratively within the Stakeholder Working Group. Other approaches than just Reliability Factors should also be considered including use of loss of load probability analysis.
- Further consideration of the shortcomings of the Minimax Regret analysis, and the potential benefits of more sophisticated risk-adjusted metrics should be evaluated in the Stakeholder Working Group.
- DESC should rely on an All Source RFP following an IRP when actual resources need to be acquired.

- The Company, in this IRP, should discuss further the impacts the ICT heat rate issue had on the Company's results, and explain the materiality of the impacts on the final costs and relative portfolio rankings.

G. Transmission System Planning and Investment

At page 30 of the 2021 IRP Update, the Company described seven (7) new transmission projects that either began or were completed in 2020, including approximately fifteen (15) miles of new transmission lines, new substations, busses and breakers, upgrades from old wooden structures to steel and iron structures, and a new tie line to Santee Cooper. All of these projects were either 115 kV or 230 kV lines. DESC states these transmission projects were necessary due to load growth within the system, and to maintain the reliability and resiliency of the system given the age and condition of existing facilities.[101]

The Company's Modified 2020 IRP identified seventeen (17) transmission projects that were tentatively scheduled for completion by the end of 2021.[102] The status of the projects that were reported in the prior IRP but not in this IRP is not clear. ORS recommends that, in addition to listing current and near-term transmission projects, the Company should also include updates on the projects that were listed in the previous IRP, including the reason for any project cancellations or significant schedule changes.

As a part of the retirement studies for the Wateree and Williams coal plants, DESC is also in the process of conducting a Transmission Impact Analysis (TIA), which is scheduled to be completed by the end of 2021.[103] Stakeholder Working Group minutes show that DESC had originally intended to perform a TIA of the Wateree plant, to be followed by a Williams TIA at a later time. In response to Stakeholder comments, the Company has changed its approach and is studying the transmission impacts of both plants concurrently.[104]

<u>Transmission System Planning and Investment Recommendations</u>

ORS recommends the Company include the following in the transmission update section of all future IRPs and IRP Updates:

- Projects underway or recently completed
- A list of upcoming transmission projects and tentative anticipated completion dates

[101] 2021 IRP Update, p. 30.

[102] DESC Modified 2020 IRP, p. 31

[103] 2021 IRP Update, p. 69.

[104] DESC IRP Advisory Group Session III Minutes, p. 6. https://www.desc-irp-stakeholder-group.com/Meeting-Presentation-and-Materials

- Updates on any upcoming projects mentioned in the prior IRP. DESC should point out project additions, cancellations, and schedule adjustments, and any other significant changes to a transmission project.

I. Distribution Resource and Integrated System Operations Plans

Act 62 states that IRPs "may include distribution resource plans or integrated system operation plans."[105] A simple reading of the act does not require the inclusion of this information. The Company states in the Revised Appendix A that these sections are not included in this IRP.[106] Despite that statement, it does appear that the Company provided some information related to the distribution resource/integrated system operations plans. That is, the Company provided a brief "Distribution Update" section that included information on the Company's System Average Disruption Index ("SAIDI"), Major Storm Outages and the Company's Advanced Metering Infrastructure initiative.[107]

It is reasonable that the Company should provide information related to distribution resource/integrated system operation plans, as it is typical industry practice for utilities to include this type of planning information in IRPs.

Distribution and Integrated System Operations Plan Recommendations

ORS recommends the Company continue to supply information on distribution resource/integrated system operation plans in all future IRPs but include more detailed updates when the Company files Comprehensive IRPs every three years.

J. Other Considerations

Stakeholder Process

Table A-4 details the topics the Commission has required the Company to engage Stakeholders on before the next IRP. These topics include:

- Load forecasts and the integration of EE impacts
- Capacity expansion model selection
- Comprehensive coal retirement analysis
- Including DSM and purchased power as resource options
- Solar capacity value

[105] https://www.scstatehouse.gov/sess123_2019-2020/bills/3659.htm Section (B)(2).

[106] ORS AIR 1-32.

[107] 2021 IRP Update p. 29

- Risk adjusted metrics for future IRPs

Based on Stakeholder Working Group meeting minutes and ORS' participation, ORS is aware that the Company has been in discussions with stakeholders regarding the following topics, among others:

- Load forecasts
- EE and DSM topics
- Capacity expansion model selection
- Coal retirement analysis approach
- Summer/winter reserve margin
- Natural gas, CO_2 and DSM forecasts
- Risk assessment metrics
- Solar ELCC/capacity contribution

ORS finds that the Company has made progress on discussing the topics required with Stakeholders. However, ORS continues to urge the participants to be cautious in the way they characterizes other Stakeholder's positions on certain issues.

The Stakeholder Working Group should be a collaborative and productive discussion. The process may not yield a consensus on every issue. Indeed, constructive disagreement is one of the most valuable components of the process. No participant should characterize any party's silence as evidence of agreement. Instead, all participants should describe the disagreements in a fair and transparent manner where appropriate.

<u>Southeast Energy Exchange Market</u>

The Company included information regarding the latest status of SEEM. The Company states that SEEM will streamline the process of buying and selling short-term energy on a voluntary basis between several electric utilities and cooperatives throughout the Southeast. The market will automate purchasing and selling energy on a 15-minute basis using a bid system that prices transactions at the midpoint between buyer bids and seller offers, and relies on transmission capacity that would otherwise be unused.[108] SEEM participants have claimed that the market will allow further growth of clean energy throughout the region and will result in up to $40 million in savings per year now and up to $100 million in savings per year across the market by 2037 assuming higher renewable and energy storage penetration occurs across the region. Those opposed to SEEM claim that the market lacks important features like an independent market monitor, and that a

[108] 2021 IRP Update Report, p. 24.

traditional RTO would enable greater customer savings and the ability to add more clean energy reliably.[109]

Since the publication of the 2021 IRP Update, FERC issued a split decision on October 13, 2021, on the SEEM, which per FERC's rules mean that the supporting parties' request to implement the SEEM was approved. The new market is scheduled to begin operation in 2022.

Participation in the SEEM will require DESC to share in the costs of starting up the new market, and in operating the market once it gets underway. If startup and operating costs are higher than planned, the anticipated benefits may be smaller than expected. ORS recommends that in the future, in each Comprehensive IRP, the Company be required to provide an analysis of the costs and benefits of participation in the SEEM. This assessment will be useful in determining if the anticipated $40 – 100 million in benefits have actually materialized and will be helpful in evaluating if continued participation in the SEEM is warranted.

Environmental Costs and Compliance

The Company discussed in the 2021 IRP Update two "emerging regulations" that it is closely monitoring. The first, is the Affordable Clean Energy ("ACE") Rule, which was devised by the EPA under the Trump administration. The ACE Rule has been vacated and remanded by the U.S. Court of Appeal, and the EPA is currently preparing a replacement rule, though no details about EPA's plans have been released. Second, the EPA is also considering adopting more stringent standards regarding the Effluent Limitation Guidelines that were finalized in 2020.[110]

Both of these standards are currently under review by the EPA and their final status remains unknown and both could potentially impact the Company's resource plans. It is reasonable that the Company should continue to monitor these rules and remain ready to adapt to any new developments.

Generator Performance Data

Order No. 2020-832 required the Company "to include several years of recent generator performance data in its IRP, along with generating unit equivalent availability factor, forced outage rate, and other data that DESC reports to the North American Electric

[109] Commissioner Glick's Fair Rates Act Statement on Southeast EEM (SEEM), https://www.ferc.gov/news-events/news/chairman-glicks-fair-rates-act-statement-southeast-eem-seem

[110] 2021 IRP Update Report, p. 26.

Reliability Corporation."[111] The Commission noted in Finding of Fact 21 that this requirement applied to the Modified 2020 IRP and future IRPs.

ORS's review of the Company's Modified 2020 IRP found the Company did not comply with this requirement, as the Company supplied "aggregated generator performance data in the form of graphs of historic outage rates,"[112] but did not supply generator level data as required. However, the Company cured this deficiency by filing the Revised Modified 2020 IRP, which added an Appendix O with the required data.

The Company's 2021 IRP Update suffers from the same deficiency as the initial filing of the Modified 2020 IRP. The 2021 Update provides aggregated generator performance data but does not provide the unit level detailed data as required. As in the Modified IRP, the Company should file a supplemental appendix with the required data. The Company should also ensure that it includes the required data in the initial filing for future IRPs.

Other Considerations and Recommendations

ORS recommends that in addition to providing generator level performance data as an update to this IRP, the Company should also file the same data as an appendix in all future IRPs and IRP Updates.

ORS also recommends in all future Comprehensive IRPs, the Company provide an analysis of the costs and benefits of participation in the SEEM.

[111] Order No. 2020-832, p. 21.

[112] ORS report on DESC's Modified 2020 IRP, p. 17.

Appendix A

The following tables outline the Commission's requirements that affect DESC's 2021 IRP Update.

Table A-1

Requirements by Commission Order No. 2021-429 (After Modified IRP)

Item	Requirements	Section VI - Ordering Paragraphs
1	Provide substantive details of the CT Plan and include it in revised modeling in the 2021 IRP Update	3
2	Adjust Reliability Factors in the 2021 IRP Update consistent with Appendix A of the Intervenor's Joint Comments	5
3	Use Dr. Sercy's Minimax Regrets and Cost Range methodologies in addition to using the "average ranking" approach to provide risk information	5
4	Develop and implement an All-Source Procurement Plan in future IRPs.	6
5	Employ a reasonable levelized cost of saved energy (LCSE) which is comparable with industry standards in conducting the upcoming Market Potential Study and in developing future IRPs starting with the 2021 IRP Update.	7
6	Present realistic and levelized DSM costs in all future IRPs starting with the 2021 IRP Update.	8
7	Use marginal line losses in the calculation of avoided costs and in the translation of energy savings from the Market Potential Study to energy savings in future IRP modeling beginning with the 2021 IRP Update.	9

Table A-2

Requirements Identified by Order No. 2020-832 (After Initial IRP) But Modified by Order No. 2021-429 (After Modified IRP)

Item	Requirements	Section VI - Ordering Paragraphs
8	Order No. 2020-832 required DESC to evaluate solar and storage options in the 2021 or 2022 IRP Updates. [113] Order No. 2021-429 specified the deadline would be the 2021 IRP Update.	2
9	Order No. 2020-832 set "cost effectiveness and achievability" as the standard for evaluating DSM measures.[114] Order No. 2021-429 updated this standard to be "cost effective, reasonable and achievable" as the standard going forward for evaluating the potential for higher savings portfolios in future IRPs and updates beginning with the 2021 IRP Update.	10

Table A-3

Requirements by Commission Order No. 2020-832

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #[115]
10	Include additional candidate resource plans, representing the near- term deployment of renewables as described in the testimony of SCSBA Witness Sercy (specifically, the resource plans identified as RP7-A and RP7-B).	4	C.1. (p. 33-34); C.2. (p. 39-40)	6.a.	3

[113] Order No. 2020-832, Evidence and Conclusions Supporting Findings of Fact, page 71

[114] Order No. 2020-832, Ordering Paragraph 6d, page 91

[115] These numbers refer to the Action Item numbers in Table 1 of ORS's Modified IRP report, pages 6-8.

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #[115]
11	Re-model the costs of all candidate resource plans: Use the flexible solar PPA cost assumptions recommended by SCSBA in the Rebuttal Testimony of Witness Sercy, and model 400 MW of Flexible Solar PPAs starting in 2023 with 20-year PPA prices of $34/MWh, $36/MWh, and $38.94/MWh	8	D.1. (p. 49-50); F. (p. 85-86)	6.b.i	7
12	Re-model the costs of all candidate resource plans: For battery storage PPAs, use the NREL ATB's low storage cost case (including capital and fixed O&M 13 costs) with the same 22% ITC safe harbor assumptions employed for solar PV PPAs.	8	D.2. (p. 51-52)	6b.ii.	8
13	Re-model the costs of all candidate resource plans: Correct the incremental flexible solar PPA capacity value assumptions to reflect the ELCC value specific to the existing system penetration level of incremental flexible solar PV.	9	D.5. (p. 58)	6.b.iii.	11
14	Re-model the costs of all candidate resource plans: Assume integration costs of $0.96 / MWh for solar PV, until an updated, Commission-approved methodology for calculating solar integration costs is available.	9	D.6. (p. 60-61); F. (p. 86)	6.b.iv.	12

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #[115]
15	Re-model the costs of all candidate resource plans: For ICT, use industry accepted ICT capital cost assumptions, such as NREL	8	D.4. (p. 55-56)	6.b.v.	10
16	Re-model the costs of all candidate resource plans: For the long-term continuing capital cost de-escalation for both solar PV and BESS, correct the implementation of the two different escalation rates consistent with Mr. Stenclik's surrebuttal testimony.	8	D.3. (p. 53)	6.b.vi.	9
17	Re-model the costs of all candidate resource plans: Re-run the production cost modeling using the AEO low, reference, and high gas prices described by SCSBA Witness Sercy in his direct testimony, and using the AEO High CO2 case, also as detailed in Mr. Sercy's direct testimony.	12	E.2. (p. 69-71)	6.b.vii.	16
18	Consistent with step 1 as identified in Hearing Exhibit 16, conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up the current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and include the results of this rapid assessment in the Modified IRP. The Company will work with the DSM Advisory Group and, if desired, a contractor selected with input from the Advisory Group, in preparing this assessment.	13	E.3. (p. 74-76)	6e.	17

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #[115]
19	Include in the Modified IRP action steps the Company will take to complete a comprehensive evaluation of the cost-effectiveness and achievability of DSM portfolios ranging from 1% to 2% savings, as identified in steps 3 through 5 of Hearing Exhibit 16.	15	E.3. (p. 74-76)	6.f.	18

Table A-4

Requirements by Commission Order Nos. 2020-832 and 2021-429 for Stakeholder Engagement

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #
20	DESC is also ordered to include load forecasts and the integration of Energy Efficiency impacts with Stakeholders as part of the 2021 IRP Update.	6, 13	C.3 (p. 41)	Order No. 2021-429 Ordering Paragraph 8 Order No. 2020-832 Ordering Paragraph 10	

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #
21	The Commission concludes that it is reasonable to require DESC to adopt and implement the use of capacity expansion software starting no later than with the development of the 2022 IRP Update. Given the importance of the choice of model, however, the Commission concludes that it is reasonable to require DESC to engage interested parties in this proceeding in a collaborative process to choose capacity expansion model for the 2022 IRP Update and future IRP proceedings. In their deliberations, collaborative members shall consider the criteria set forth in Hearing Exhibit 6, Exhibit AS-2, with particular attention to the criteria numbered 1-7 and 9-12.	3	B.(p. 24-29), (p. 91-92)	Order No. 2020-832 Ordering Paragraph 7.a, 8.a	ORS Sufficiency Report Action Item #2
22	DESC is required to perform a comprehensive coal retirement analysis to inform development of the 2022 IRP Update, and to solicit parties' recommendations on guidelines for performing this analysis and approve a set of guidelines prior to DESC's 2022 IRP Update development process via the ongoing IRP Stakeholder Process.	4, 5, 13	C.2 (p. 34-41) E.2 (p. 70)	Order No. 2020-832 Ordering Paragraph 7.c,i.	ORS Sufficiency Report Action Item #4
23	DESC should include DSM and Purchased Power as resource options in the 2021 IRP Update — if achievable — or 2022 IRP Update and future IRPs. It is expected that Dominion will consider the input of Stakeholders in the evaluation of the purchased power and DSM modeling.	6	C.3 (p. 41-44)	Order No. 2020-832 Ordering Paragraph 7.e.	ORS Sufficiency Report Action Item #5
24	Prospectively, Dominion shall work with Stakeholders regarding fair inclusion of solar PV's winter capacity value in the 2021 and 2022 IRP Updates. This should be a good-faith attempt to reach a mutually agreeable value to propose for assignment for PV capacity value in the winter.	9	D.5 (p. 56-58)	Order No. 2020-832 pp. 58	

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #
25	A Stakeholder process is an appropriate venue for further refining the risk-adjusted metrics that DESC should apply to future IRPs. The Commission will require DESC to implement the cost range and minimax regret analyses in the Modified IRP and subsequent updates and will consider more refined and sophisticated risk-adjusted metrics in the 2022 IRP Update.	11	E.1 (p. 61-64)	Order No. 2020-832 Ordering Paragraph 8.g.	ORS Sufficiency Report Action Item #14
26	The Commission finds persuasive the critiques of DESC's approach to load forecast sensitivities. DESC appears to acknowledge that is an area where its approach to devising the IRP can be improved, but that this is not a fix than can be implemented in time for the Modified IRP. Therefore, the Commission will require DESC, in the 2022 IRP, to work with Stakeholders to develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast	13	E.2 (p. 66,70)	Order No. 2021-429 Ordering Paragraph 3	ORS Sufficiency Report Action Item #15

Item	Requirements	Section IV - Finding of Facts	Section V - Evidence and Evidentiary Conclusions	Section VI - Ordering Paragraphs	ORS Modified IRP Report Action Item #
27	The Commission adopts Steps 3 through 5 as discussed in Witness Hill's Late-Filed Exhibit, and DESC is directed to include this comprehensive evaluation in the 2023 IRP. In the 2023 IRP, DESC must include a comprehensive evaluation of the cost effectiveness and achievability of higher levels of savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%. As outlined in step 3 of the late-filed exhibit, this comprehensive evaluation must consider substantive additions and modifications to the Company' existing DSM portfolio. In implementing this plan, DESC must work with Stakeholders, particularly the Advisory Group, and provide opportunities for iterative review, input, and feedback on the Company's analysis and subsequent portfolio development. As part of this presentation in the 2023 IRP, DESC shall include potential incentive options and best practices to achieve the modeled levels of DSM.	14-16	E.3 (p. 76)	Order No. 2020-832 Ordering Paragraph 9	ORS Sufficiency Report Action Item #19
28	DESC is also ordered to include load forecasts and the integration of Energy Efficiency impacts with Stakeholders as part of the 2021 IRP Update.	6, 13	C.3 (p. 41)	Order No. 2021-429 Ordering Paragraph 8 Order No. 2020-832 Ordering Paragraph 10	